3. In many wells in west and north-central Texas, an uncased borehole or uncemented borehole-casing annulus will stay open indefinitely, and may not be safely assumed to contain the full amount of mud or cement indicated by well records.

Kent, Robert T., November 20, 1985, Personal Communication: Underground Resource Management, Inc., Austin, Texas .

SUMMARY:

This discussion with Kent dealt primarily with geologic variations between geographic regions. Kent was mostly concerned with whether or not the drilling fluid in the well at closure was retained in place.

In Gulf Coast wells with no longstring casing the well bores slough and the shales swell trapping the mud. In this case, assuming the mud column hydrostatic head based on a mud filled hole, should be valid. When the hole is cased, a mud filled hole cannot be safely assumed, unless a record is available indicating the presence of mud at closure. Some operators abandoned depleted or dry wells without bothering to fill the well with mud. Formation water from the zone of interest could then enter the open hole and corrode the casing, to create a channel for fluids to escape to the surface from a formation outside the casing.

Though west Texas formations are usually competent, thief zones are common within the production reservoirs in the northern Caprock areas around Lubbock and Amarillo. Where thief zones occur, drilling fluids remaining in an open hole below surface casing, may drain to a level that the hydraulic pressure of the thief zone will support.

Kent indicated that, when documentation exists that an abandoned wellbore was filled with mud, and lost circulation problems were not present, assuming the hydraulic head for the full mud column is justified. Coastal wells and wells in the Odessa area fall in this category. He warned, however, that in cased holes and areas where low pressure zones exist, the wellbore may be empty or partially filled with mud. In these cases injection should be limited to maintain the injection zone pressure below that of the low pressure lost circulation zones. In spite of these problems, Kent indicated that injection of liquid wastes into deep wells is a preferred method of disposal under the proper geohydrologic conditions.

CONCLUSIONS:

1. Assuming a mud hydrostatic head based on a mud-filled column should be valid in uncased Gulf Coast abandoned wells where unstable formations can bridge over a hole.

2. In cased abandoned wells, a mud column may be absent or reduced significantly if mud has been removed for production or testing, and was not replaced. Unless records indicate otherwise, it should be assumed that the mud does not completely fill the casing in these wells.

3. In the northern Cap Rock area of west Texas, where low pressure zones exist, the drilling fluid and cement may drop to the levels of thief zones. Injection should be limited so that reservoir pressures do not exceed the mud column hydrostatic head calculated from the depth of the thief zone.

Kent, Robert T., and Bentley, Michael E., 1985, Risk Assessment of Deep Well Injection Systems: Second Annual Canadian-American Conference on Hydrogeology, Banff.

SUMMARY:

Concerning injection well failures by upward fluid migration through artificial penetrations, it should be noted that standard cementing practice for the long-string or production casing of oil or gas wells is to cement only the lower 600 to 1,000 feet of casing, leaving the borehole-casing annulus full of drilling mud.

Numerous wells around the perimeter of the Barbers Hill Salt Dome at Mont Belview, Texas have uncemented sections of long-string casing, due to lost circulation problems experienced in the cavernous cap rock penetrated by these wells. This cap rock comprises an injection reservoir for salt water injection wells at the Barbers Hill dome. In 1975, several abandoned oil wells at the dome began to flow salt water to the ground surface during periods of injection operations taking place nearby. It is believed that waste brine encountering uncemented portions of the long-string casing in the abandoned wells, may have caused corrosion of the casing and a consequent flow of brine through the open casing to the ground surface.

In 1970, an oil well one mile away from a brine injection well in Scurry County in west Texas, developed a wellhead pressure adequate to flow salt water to the ground surface. Analyses of the brine collected from the uncemented oil well annulus indicated a strong similarity to brine from the nearby injection well. From records showing the long-string casing of the oil well to be uncemented through the injection zone, it was hypothesized that casing corrosion by injected or native brines had allowed the injected brine to be produced from the oil well.

Cases of abandoned wells beginning to flow near injection well sites have also been reported in the 1930's in Michigan, and in southwest Ontario in the late 1960's. In these hard rock areas, a large number of wells had been drilled and abandoned by cable tool methods. Since cable tool drilling does not use drilling fluid, most of these wells were probably abandoned without mud in the wellbore.

Whereas the noted examples including cap rocks of salt domes, and hard rocks in west Texas, Michigan, and Ontario, point out the potential danger of upward flow in regions where wellbores stay open, it is believed that in areas of unconsolidated strata, drilling mud and natural sealing of wellbores provide some protection against fluid flow.

CONCLUSIONS:

1. For oil and gas wells constructed by rotary drilling techniques, standard practice for cementing long-string casing is to cement only the lower 600 to 1,000 feet of casing, leaving the borehole casing annulus full of drilling mud.

2. Documented cases from areas of consolidated rocks have shown that abandoned or producing wells without casing cemented through an injection zone may produce fluids as a direct result of nearby injection well operations.

3. In areas of unconsolidated strata, drilling mud and natural sealing of wellbores may provide some protection against fluid flow.

Marr, J.J., November 6, 1985, Personal Communication: Resource Enginering, Houston, Texas.

SUMMARY:

Marr indicated that mud gel strengths increase with time and temperature under abandoned well conditions. In fact, some gypsum and lime base muds solidify so that difficulty is experienced during drilling out of abandoned wells. Both bentonite and gyp additives tend to exhibit high gel strengths. In areas where formation materials are swelled by water, sloughing and caving in of the hole results. The bore hole heals over and the formation approaches original predrilled conditions. In areas where formations are consolidated the drilled hole remains unchanged.

Formations used for waste disposal along the Gulf Coast are mostl unconsolidated and subject to caving and sloughing discussed above. Abandoned wells located in West Texas maintain the original diameter with time so that a hole may be recovered by merely washing out with a drill bit. In an inadequately plugged well in this area pressure control depends on the mud head and gel strength. Abandoned wells in these areas are more likely to lose fluids when the zone is overpressured.

Wells drilled prior to World War II used natural mud with no control of density or viscosity. Many times the natural mud remaining in the well bore had high densities (up to 15 lb/gal). The minimum density of wellbore muds (natural and modern drilling muds) is considered to be 9 lb/gal. Additives to drilling muds have resulted in high gel strengths which under well bore conditions could require a substantial pressure to displace the mud. In some cases the mud has solidified.

CONCLUSIONS:

1. Mud gel strengths increase with time and temperature. Some gypsum and lime base muds solidify to a stage that hinders drilling out abandoned wells.

2. Formations generally used for waste disposal zones along the Gulf Coast tend to be unconsolidated and subject to sloughing and caving in of the well bore. As a result the bore hole may heal over so the formation may approach original conditions.

3. Formations in West Texas are well consolidated so that the bore hole remains intact. Inadequately abandoned wells completed in a waste disposal zone could lose fluids when th zone is overpressured.

4. Wells abandoned before World War II were drilled with natural mud which could result in high density mud (as much as 15 lb/gal).

5. The minimum density of wellbore muds is considered to be 9 lb/gal.

Meers, R.J., November 7, 1985, Personal Communication: Pollution Control & Waste Disposal, Inc., Metairie, Louisiana.

SUMMARY:

Meers stated that mud density is a major factor in controlling pressures in abandoned wells, and the gel strength would be an added benefit. Gel strengths can be significant in wells as illustrated during the reentry of old wells in Maryland to complete cementing of the annulus outside the casing. After perforating the casing above the original cement, the original mud outside the casing was circulated to the surface. The pressure required to break the gel was great enough to require a packer above the perforations to protect the casing. Also in old wells in the Orange Du Pont Plant in 1977 plugs of gelled mud in the open well bore have been observed to be more resistant to drilling than the original formation.

Abandoned wells along the Gulf Coast probably are sealed off due to sloughing of the formation and briding of the hole. For this reason the Gulf Coast is a good location for a waste disposal well.

In the West Texas area, the formations usually used for waste disposal are well consolidated and well bore holes remain intact. As a result abandoned wells drilled into these zones would be more susceptible to losing fluid when overpressured.

Wells drilled prior to 1940 were generally abandoned with little thought given to proper plugging procedures. These wells rarely exceeded 4000 feet depth and should not endanger most injection operations as the waste disposal zones generally exceed this depth.

CONCLUSIONS:

1. Mud density is a major factor in controlling pressures in abandoned wells, however, gel strength is an added benefit.

2. Mud gel in the annulus outside the casing of a well required considerable pressure to break down and circulate out of the well.

3. Drillers have encountered plugs of gelled mud in a well bore that were more resistant to drilling than the original formation.

4. Abandoned wells along the Gulf are probably sealed off due to sloughing of the formation and bridging of the bore hole, consequently, reservoirs in this area are excellent for injection of wastes.

5. **West Texas formations are generally consolidated and well bore holes do not heal over. Consequently, abandoned wells penetrating waste disposal holes could lose formation fluids if inadequately plugged.**

Price, William Henry, 1971, The Determination of Maximum Injection Pressure for Effluent Disposal Wells - Houston, Texas Area, M.S. Thesis, University of Texas at Austin.

SUMMARY:

Regarding abandoned wells, Price indicated that dry holes in the Houston-Galveston area which were improperly plugged, must be a primary consideration in setting maximum injection rates and volumes for injection wells. In contrast with modern well-plugging standards involving combinations of properly set cement plugs within a mud-filled wellbore, many dry holes in this area of the Gulf Coast were improperly plugged with only mud in the wellbore. Price further indicated that .01 psi per foot of depth was the maximum advisable pressure build-up at an improperly plugged well which lacked mud density data. This suggested limit is based on the pressure gradient difference between a 9.2 lb/gal mud (@ .477 psi/ft) and a normally-pressured formation piezometric head (@ .467 psi/ft). The probabilities that a mud of unknown density actually exceeds 9.2 lb/gal, and that many Gulf Coast wellbores will be sealed by wall sloughing and clay swelling, combine to make .01 psi/ft a conservative amount of pressure build-up for an improperly plugged or inadequately documented well.

CONCLUSIONS:

1. Judged by modern plugging standards, many Gulf Coast area wells were improperly plugged by filling with heavy mud without setting down-hole cement plugs.

2. Improperly plugged or inadequately documented wells in the Gulf Coast area will safely withstand downhole pressure build-ups to the degree to which the well-bore mud hydrostatic pressure exceeds the reservoir pressure.

Schuh, Frank J., November 19, 1985, Personal Communication: Atlantic Richfield Company, Dallas, Texas.

SUMMARY:

This discussion with Schuh dealt largely with drilling fluids and cement plugs, and their capacity to contain fluids in wells. He also cited cases in which drilling mud was used above packers and found to be unsatisfactory because of difficulty in unseating the packers after the mud gelled. Schuh indicated that untreated mud columns tend to set up as the pH decreases from breakdown of organic constituents in the mud. Muds also thicken due to filtration, as fluids bleed from the mud to surrounding pays. In shale zones where filtration is extremely low, the fluid column remains intact and is effective in the control of pressure. It is desirable, therefore, that the injection zone be separated by a thick shale zone to maintain a mud column of sufficient height to control the waste zone pressure.

In old wells drilled in the 1930's and earlier, the clay muds used at that time have thickened and solidified to the point that considerable pressure can be contained. When using these muds as drilling fluids, mud thinners had to be added to decrease viscosity and gel strength.

As a side issue, Schuh mentioned that failure of cement plugs had been experienced when located next to a gas zone. In these cases it was concluded that during the setting process, the internal pressure in the cement plug dropped to that of the surrounding formation, allowing gas to penetrate the plug and render it useless.

CONCLUSIONS:

1. Untreated mud columns tend to set up as pH is reduced.

2. Mud columns become thicker and more dense due to filtration losses to the surrounding pays.

3. Mud columns remain intact and effectively control pressure in shale and other impermeable zones where filtration is nil. It is desirable, therefore, to have thick impermeable zones between the waste zone and ground water to prevent loss of the fluid column.

4. Clay muds used in old wells in the 1930's and earlier, have thickened and solidified sufficiently to contain considerable reservoir pressure build-ups.

5. Failure of cement plugs has occurred when set opposite gas zones. During setting of the plug, pressure in the cement

plug dropped to that of the surrounding formation, allowing gas to penetrate and destroy the plug.

Smith, Dwight, November 8, 1985, Personal Communication: Halliburton Services, Duncan, Oklahoma,

SUMMARY:

Smith indicated that it was impossible to predict the gel strength of mud in an abandoned well, or the probability of a mud retaining fluids in an overpressured reservoir. The somewhat pessimistic opinion on the benefits of mud gel in abandoned wells is based on the lack of data to substantiate mud gel strengths in a well after an extended time. Smith stated that over long periods of time at elevated temperatures, mud gels will break down into pockets of filtercake and fluid. Also, hydrochloric acid can shrink mud gel so that mud-filled intervals may be breached by channels.

Smith cited a case in Pennsylvania where casing in an overpressured zone was ejected from an abandoned well which was adjacent to the injection well. Also in Kankakee, Illinois, an overpressured gas storage reservoir resulted in gas intrusion into the surrounding farmer's water wells rendering them unfit for use.

Bentonite muds were first introduced to improve mud gel strength in the 1930's. Prior to that time, native drilling muds comprised of drill cuttings and water, had poor gel strengths. Wells drilled before 1930 generally did not exceed 4,000 feet in depth. Because most waste disposal zones for industrial wells are below this depth, these pre-1930 wells should exert little or no influence on waste disposal well projects. Plugging records of wells abandoned prior to 1960 are usually not well documented, and are not generally reliable as a result.

Boreholes in abandoned wells in the Gulf Coast region probably close over time, due to sloughing, or caving, of the borehole walls, and healing of the pay. In west Texas and the Panhandle, zones used for waste disposal are relatively consolidated, and will maintain boreholes in an open condition for an extended time. "Red beds" in some areas of west Texas, are the principal zones of instability that would be likely to slough and seal a well bore.

CONCLUSIONS:

1. It is not possible to predict gel strength in an abandoned well.

2. Mud gel in contact with hydrochloric acid may shrink sufficiently to cause channels to breach the mud-filled intervals.

3. Wells drilled prior to the mid 1930's used native muds which had poor gel strengths.

4. Wells drilled before 1930 generally were less than 4,000 feet in depth and consequently do not penetrate most disposal zones for industrial waste disposal wells.

5. Abandoned wells on the Gulf Coast area have a higher probability of borehole closure by sloughing of the borehole than wells in west Texas and the Panhandle. Red bed clays in west Texas and Panhandle are the principal zones of borehole instability in these areas.

Williams, C.C., 1948, Contamination of Deep Water Wells in Southeastern Kansas: State Geological Survey of Kansas, Bulletin 76

SUMMARY

Williams documented some of the modes of ground-water contamination which have occurred through producing or abandoned wells, in which care has not been taken to prevent interformatinal fluid flow. In southeastern Kansas, highly mineralized water from the Cherokee Shale has entered numerous deep water wells. The practice of setting well casing without completely cementing (grouting) the borehole-casing annulus, has allowed mineralized formation waters to enter the well by corroding through the casing, and by traveling down the unsealed annulus to the well completion zone. It was therefore recommended by the State Geological Survey, and the Kansas State Board of Health, that the borehole-casing annulus of all wells be sealed by grout through all zones of inferior water quality, to protect steel casing from corrosion, and to maintain the quality of local aquifers which supply fresh water for domestic uses.

CONCLUSIONS:

Cases documented in the southeastern part of Kansas indicate that failure to seal the borehole-casing annulus of a well during construction, may subject a well to casing failure by corrosion, and/or to vertical flow of fluids between formation.

APPENDIX 4-10

Appendix 4-10

Factors Affecting the Area of Review for Hazardous Waste Disposal Wells (Davis, 1986)

PROCEEDINGS OF THE INTERNATIONAL SYMPOSIUM ON SUBSURFACE INJECTION OF LIQUID WASTES

March 3-5, 1986
Royal Sonesta Hotel
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FACTORS EFFECTING THE AREA OF REVIEW

FOR HAZARDOUS WASTE DISPOSAL WELLS

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Abstract

The area of review, for a hazardous waste disposal well, is defined as the radial distance from the receiving well in which the pressure, caused by injection, increases sufficiently to possibly cause migration of fluids into useable sources of drinking water (USDW). Among the potential conduits for fluid migration from the disposal formation are improperly plugged well bores, channeling behind the casing of the injection well, faulted formations, solution channels, naturally fractured formations or facies pinch-outs. Usually faults, solution channels and most other naturally occurring geological conduits are filled with native fluids and are frequently sealed from USDWs by secondary mineralization. This paper concerns itself with only those conduits that are man-made.

Man-made conduits such as old abandoned test holes or oil and gas wells are sealed with cement plugs and drilling mud. The static mud column provides substantial resistance to upward flow. Most mud systems develop a gel structure when allowed to remain quiescent. To initiate flow up an improperly abandoned well bore, the pressure in the disposal zone must exceed the sum of the static mud column pressure and the mud gel strength pressure. If the sum of these values is not exceeded during the life of a hazardous waste disposal well, there is no potential for contamination of USDWs. This paper presents a simplified procedure which can be used to calculate that effected area.

Introduction

The area of review, for a deep injection well, is determined by the zone of endangering influence for the life expectancy of that well. The zone of endangering influence is defined as that area the radius of which is the lateral distance in which pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water (USDW).

Factors affecting this area of review are the radial extent of ground water movement from the well bore, the rate of pressure build-up in the reservoir, through time, at various distances from the well bore and the potential for upward migration of fluids through man-made conduits.

The prediction of the probable rate of pressure increase and radial fluid movement in the disposal reservoir, resulting from the injection of fluids is a problem often confronted by injection well operators and regulatory agencies. Fluid injected into a formation which is already liquid filled will result in an increase in pressure in that formation. This injected fluid must be accommodated by either one or a combination of the following; expansion of the pore space in the matrix rock, compression of either or both the formation and injected fluids or expulsion of the formation water.

The resulting increase in pressure in the receiving formation due to the injection of fluids pose potential environmental threats to our USDWs if any man-made conduits exist within the area of review. Among the potential conduits for fluid migration from the disposal formation are improperly plugged well bores, channeling behind the casing of the injection well, faulted formations, solution channels, naturally fractured formations or facies pinch-outs.

Factors Effecting the Area of Review

Area of Review

The radius of the area of review for an injection well is determined either by calculating the zone of endangering influence or by using a fixed radius from the well bore which ever is less. The distance of the fixed radius varies from state to state. In states where the Environmental Protection Agency (EPA) has primacy, the fixed radius is 1/4 mile, while in primacy states or states that set their own regulatory standards so long as they meet or exceed EPA standards, the fixed radius varies from 1/4 mile to 2-1/2 miles.

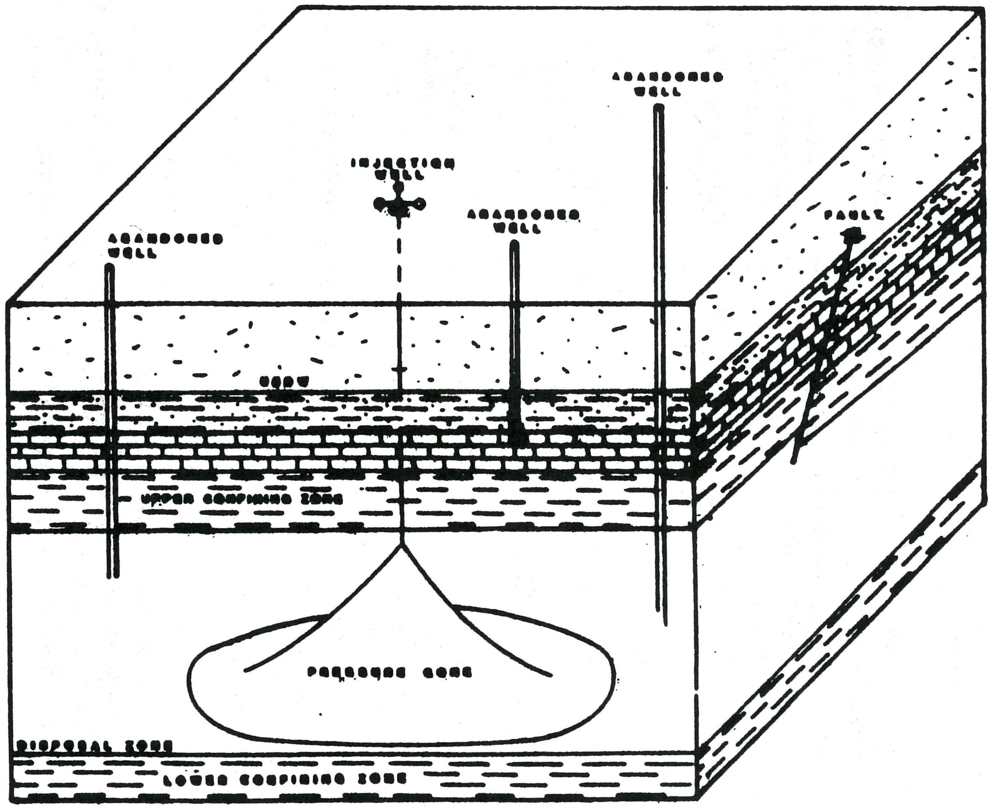
Computation of the zone of endangering influence should be calculated for an injection period equal to the expected life of the well. There are several equations that can be used for determining the area of review. The most notable and widely used is shown below (Barker, 1971; Ferris, et al, 1962; Kruseman and DeRidder, 1970; Lohman, 1972).

$$h = \frac{Q}{4\pi T}\left(-0.577216 - \log_e u + u - \ldots - \frac{u^2}{2 \times 2!} + \frac{u^3}{3 \times 3!} - \ldots\right) \qquad (1)$$

where

$$h = \frac{r^2 S}{4Tt}$$

FIGURE 1
SCHEMATIC SHOWING FACTORS
AFFECTING THE AREA OF REVIEW



and

h = hydraulic head change at radius r and time t
Q = injection rate
T = transmissivity
S = storage coefficient
t = time since injection began
r = radial distance from well bore to point of interest.

For large values of time, small values of radius of investigation, or both, Equation 1 can be reduced to:

$$\Delta h = \frac{2.30Q}{4\pi T} \log \frac{2.25Tt}{r^2 S} \qquad (2)$$

Unfortunately, this equation does not address all the possible well configurations, multiple well systems, reservoir conditions, skin effects and other variables and combinations thereof. Warner, et al (1979) posed the use of several equations based on specific conditions of the system being evaluated. They indicated that an adequate approximation of the pressure build-up caused by injection into infinite confined reservoirs can be determined if we assume

1. Flow is horizontal.
2. Gravity effects are negligible.
3. The reservoir is homogeneous and isotropic.
4. The injected and reservoir fluids have a small and constant compressibility.
5. The receiving reservoir is infinite in areal extent and is completely confined above and below by impermeable beds.
6. Prior to injection the piezometric surface in the vicinity of the well is horizontal, or nearly so.
7. The volume of fluid in the well is small enough so that the effect of the wellbore can be neglected.
8. The injected fluid is taken into storage instantaneously. That is, pressure effects are transmitted instantaneously through the aquifer.

The basic differential equation for the unsteady radial flow of a slightly compressible fluid from an injection or other type well is (Matthews and Russell, 1967)

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} = \frac{\phi u c}{k}\frac{\partial P}{\partial t} \qquad (3)$$

where:

Symbol	Parameter or Variable	Practical Units
c	compressibility	psi^{-1}
Q	porosity	decimal fraction
h	reservoir thickness	feet (ft)
k	permeability	millidarcies (m)
u	viscosity	centipoise (cp)

p	pressure	psi
q	flow rate	stock tank barrels/day (STB/D)
r	radial distance	feet (ft)
t	time	days (D)

The pressure build-up equations used by Warner, et al (1979) were written using dimensionless pressure (P_D) and dimensionless time (t_D). These dimensionless quantities are groups of variables that commonly occur in build-up equations and can be conveniently replaced by a single term. Dimensionless time, for the units listed above is:

$$t_D = \frac{6.33 \times 10^{-3} kt}{\phi \mu c r^2} \tag{4}$$

In unsteady state or transient flow equations, dimensionless pressure (P_D) is a function of dimensionless time and, perhaps, other quantities, depending on the particular buildup solution. It is defined for each equation in which it is used, throughout the Warner report.

The Warner equations presented all contain the variable β, the formation volume factor, which is the ratio of the volume of the fluid being injected at reservoir pressure compared with the volume at standard conditions (520°R, 14.7 psi). For liquids, β can, for practical purposes, be considered to be 1.0, as in all examples in this report. However, β is quite variable when the injected fluid is gas. When a highly compressible fluid is being injected, β should be evaluated at an average reservoir pressure. In cases where the pressure is not known, enter a value of β = 1.0, obtain the approximate pressure, then evaluate β (Amyx, et al, 1960) and recalculate the pressure.

Multiple Well Effects

As indicated in Figure 2, if we assume a constant injection rate for a single well penetrating the entire receiving aquifer, and adjust for practical units, the differential equation, Equation 3, has a solution of the form

$$P_r = P_i + 70.6 \frac{q\mu\beta}{kh} \left[Ei \left(\frac{39.5\ \phi\mu c r^2}{kt}\right)\right] \tag{5}$$

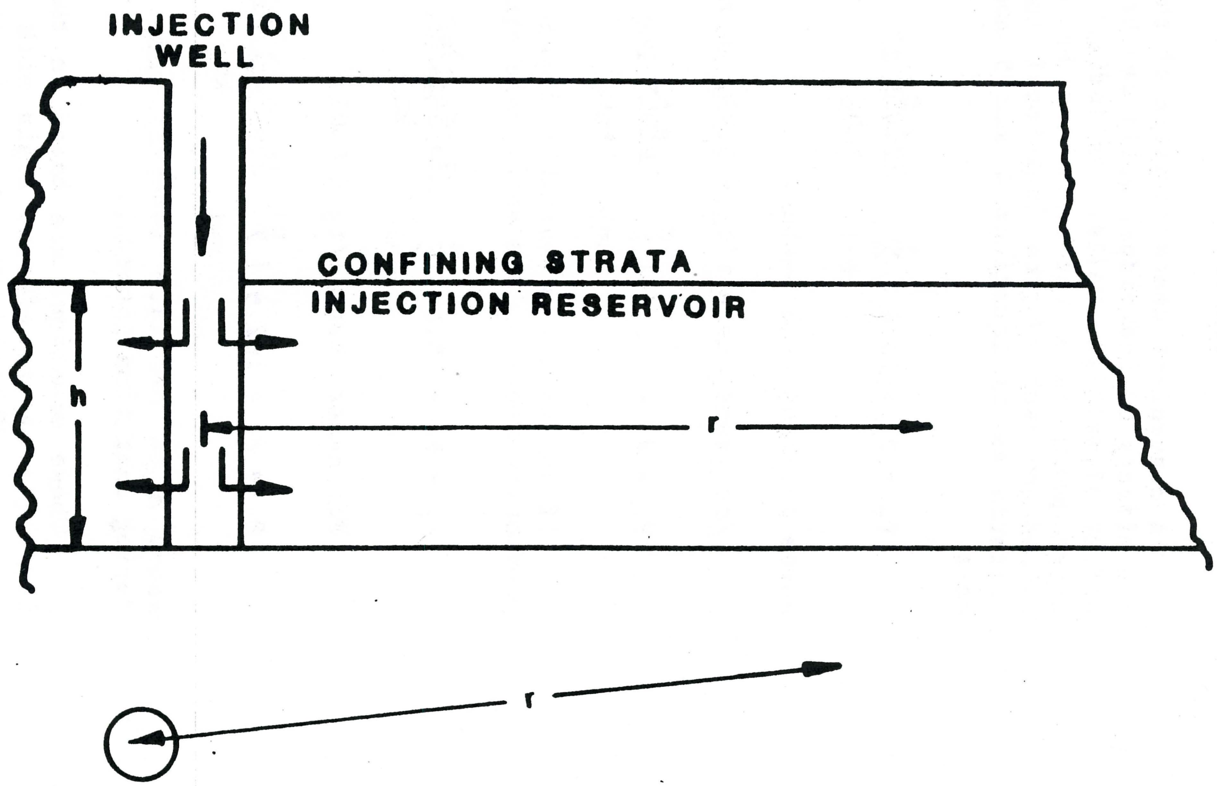
and for the case where $1/t_d < 0.01$. This is approximated as

$$P_r = P_i + 162.6 \frac{q\mu\beta}{kh} \log\left(\frac{kt}{70.4\ \phi\mu c r^2}\right) \tag{6}$$

where

FIGURE 2

PROFILE AND PLAN VIEWS OF A COMPLETELY PENETRATING WELL INJECTING INTO A CONFINED RESERVOIR. PRESSURE IS TO BE CALCULATED AT A POINT r DISTANCE FROM THE WELL.
(FROM WARNER, et.al. 1979)



Symbol	Parameter of Variable	Practical Units
β	formation volume factor	Std Stk Tank BBL (RB/STB)
P_r	reservoir pressure at radius r	psi
P_i	initial reservoir pressure	psi

A convenient characteristic of these equations (Warner, 1979) is that the effects of individual wells can be superimposed to obtain the combined effect of multiple wells. As indicated in Figure 3, the pressure at any given point in a reservoir can be evaluated by summing the pressures caused by each of the individual injection wells. Assuming the same criteria as in Equations 4 and 5 above, except for multiple wells, we have

$$P_r = P_i + 70.6 \left[\sum_{n=1}^{m} \frac{q_n \mu_n \beta_n}{k_n h_n} \, Ei \left(\frac{39.5 \, \phi_n \mu_n c_n r_n^2}{k_n t_n} \right) \right] \qquad (7)$$

where n is the well number.

For cases where $1/t_d < 0.01$, an adequate approximation is

$$P_r = P_i + 162.6 \left[\sum_{n=1}^{m} \frac{q_n \mu_n \beta_n}{k_n h_n} \log \left(\frac{k_n t_n}{70.4 \, \phi_n \mu_n c_n r_n^2} \right) \right] \qquad (8)$$

If we assume a variable injection rate for the same criteria as previously applied, the applicable equation is

$$P_r = P_i + 70.6 \left[\sum_{a=1}^{n} \frac{(q_a - q_{a-1}) \mu \beta}{kh} \, Ei \left(\frac{39.5 \, \phi \mu c r^2}{k(t - t_{a-1})} \right) \right] \qquad (9)$$

For cases where $1/t_d < 0.01$

$$P_r = P_i + 162.6 \left[\sum_{a=1}^{n} \frac{(q_a - q_{a-1}) \mu \beta}{kh} \log \left(\frac{k(t - t_{a-1})}{70.4 \, \phi \mu c r^2} \right) \right] \qquad (10)$$

where a is the time interval under consideration and q_a is the rate during that time interval.

These equations are based on the principle of superposition. That is, the pressure effects begin with the initial injection period t_1 and rate q_1. When a new rate q_2 is implemented, it is as if a new well begins to operate at that rate, with the effects superimposed on the original well, while the original well continues to operate at rate q_1. This performance is shown diagrammatically in Figure 4.

FIGURE 3

PROFILE AND PLAN VIEWS OF TWO COMPLETELY PENETRATING WELLS INJECTING INTO A CONFINED RESERVOIR. PRESSURE IS TO BE CALCULATED AT A POINT AT RADII r_1 AND r_2 FROM WELLS 1 AND 2 RESPECTIVELY.

(FROM WARNER, et.al. 1979)

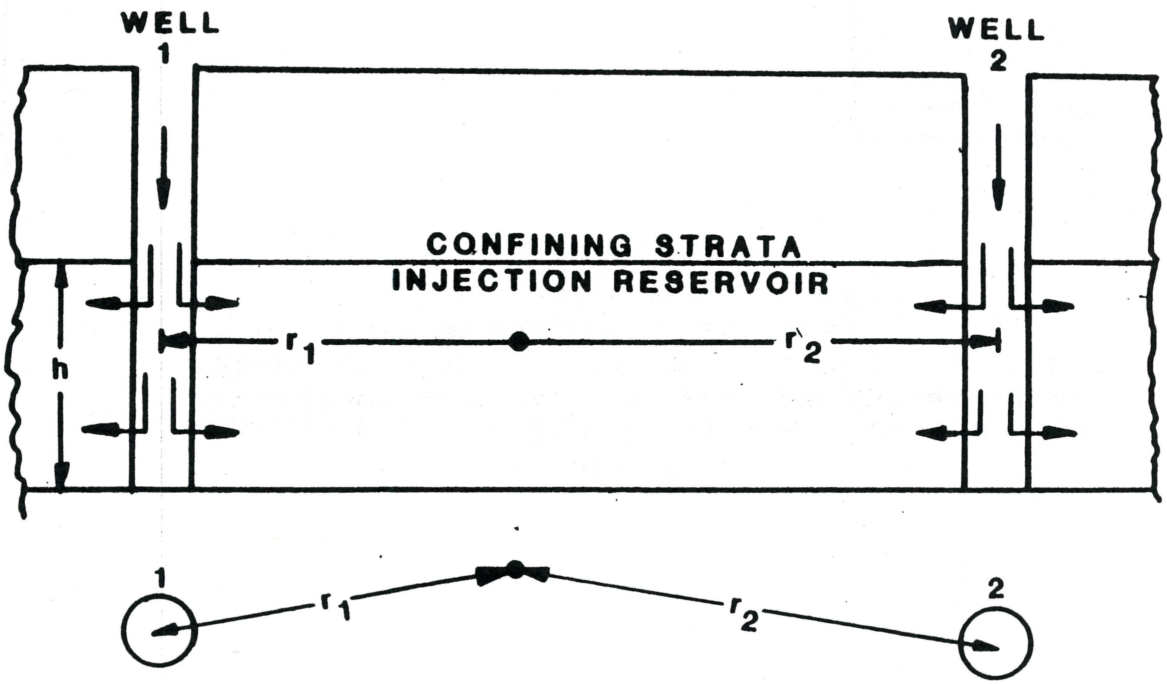
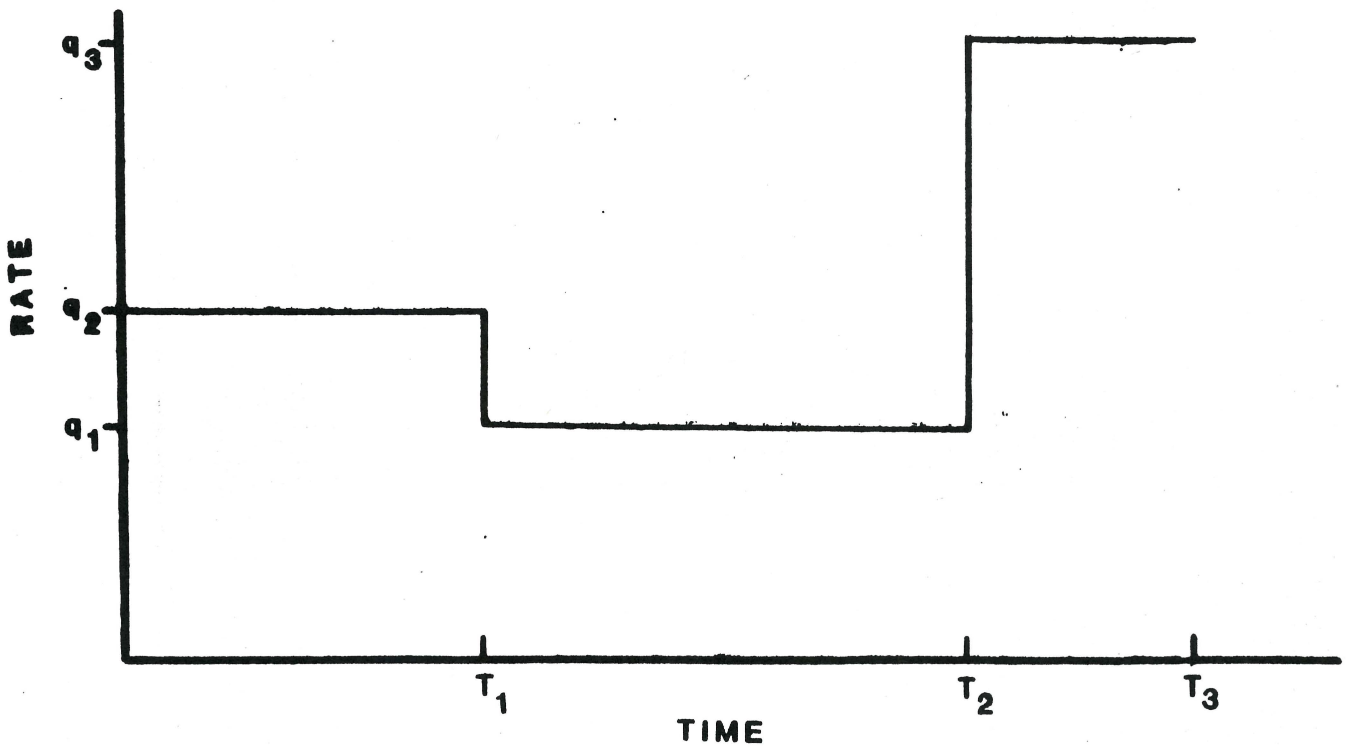


FIGURE 4

DIAGRAMMATIC REPRESENTATION OF THE INJECTION HISTORY OF AN INJECTION WELL OPERATING AT A VARIABLE RATE,

(FROM WARNER, et.al. 1979)



In computing the pressure buildup caused by multiple injection wells operating at variable rates, the principle of superposition is applied twice, once for computation of the pressure effects of each well and a second time in summing the effects of the individual wells. Figure 2 depicts two wells whose effects must be summed and Figure 3 shows a possible pattern of variable rate injection that might exist.

The applicable equation is:

$$P_r = P_i + \left[\sum_{b=1}^{m} \sum_{a=1}^{n} \frac{70.6(q_{ba}-q_{b(a-1)})}{k_b h_b} \; Ei \left(\frac{39.5\phi_b \mu_b c_b r_b^2}{k_b(t_b-t_{b(a-1)})} \right) \right] \qquad (11)$$

Where b is the well number, a is the time interval under consideration for well b, and q_{ba} is the rate for well b during time interval a. For cases where $1/t_d < 0.01$, an adequate approximation is:

$$P_r = P_i + \left[\sum_{b=1}^{m} \sum_{a=1}^{n} \frac{162.6(q_{ba}-q_{b(a-1)})}{k_b h_b} \; \log \left(\frac{k_b(t_b-t_{b(a-1)})}{70.4\phi_b \mu_b c_b r_b^2} \right) \right] \qquad (12)$$

In summary, these two equations state and perform the calculation for each well, as done for the single-well variable-rate case and then sum the effects of the wells.

Skin Effects

Warner, et. al. (1979) also addressed the effects of skin damage. Injection wells may suffer permeability loss in the vicinity of the wellbore during construction or operation or they may experience permeability gain. Permeability loss can result from drilling mud invasion, clay-mineral reactions, chemical reactions between injected and aquifer water, bacterial growth, etc. Permeability gain can result from chemical treatment such as acidization or from hydraulic fracturing and other mechanical stimulation methods. These permeability changes, which occur in the immediate vicinity of the wellbore are called "skin effects" by the petroleum industry and are described by a "skin factor" (van Everdingen, 1953; Hurst, 1953). The skin factor (s) is positive for permeability loss and negative for permeability gain.

The skin factor can vary from about -5 for a hydraulically fractured well to + ∞ for a well that is completely plugged (Earlougher, 1977). The incremental pressure difference caused by the skin effect is described by:

$$\Delta P_s = s \frac{q}{2\pi kh} \qquad (13)$$

Equation 13 is applied by combining it with equations that are derived for pressure buildup without skin effects. For example, Equation 5 is rewritten below to include skin effects:

$$P_r = P_i + \frac{70.6q\mu\beta}{kh} [Ei\left(\frac{39.5\phi\mu cr^2}{kt}\right) + 2s] \quad (14)$$

When $1/t_d < 0.01$, an adequate approximation of Equation 14 is:

$$P_r = P_i + 70.6 \frac{q\mu\beta}{kh} [\ln\left(\frac{kt}{70.4\phi\mu cr^2}\right) + 2s] \quad (15)$$

Equations 14 and 15 are only valid at the wellbore. No equations are presented here for calculation of pressure buildup near the wellbore, in the zone of damage or improvement, because this zone is relatively thin and because the calculations are of relatively limited applicaton. Outside of the skin zone, the standard equations can be applied with no correction (Earlougher, 1977). The thickness of the skin is determined by (Hawkins, 1956):

$$r_s = r_w e^{s\ k_s/k-k_s} \quad (16)$$

Seldom if ever, will k_s be known. Reasonable estimates of k_s can, however, be made to allow calculation of the range of possible skin thicknesses. Consideration of the sources of permeability reduction around a wellbore indicates that, in the case of wellbore damage, r_s would seldom be greater than a few feet. The radius of permeability improvement can be greater, in the tens of feet for an ordinary hydraulic fracturing program, but probably less than 100 feet as the maximum r_s, except in cases of massive hydraulic fracturing.

It should be noted that these equations can only be used for pressure buildup at the well. As discussed above, s is assumed to be zero and the ordinary buildup equations should be applied for points outside of the skin zone, which is estimated by Equation 16 or assumed to be less than 100 feet, if Equation 16 can not be used.

It is generally assumed, in estimating the pressure effects of injection wells, that the wells will be drilled completely through the injection reservoir. This will usually be true, since it maximizes the injection efficiency of the well. However, for mechanical or geological reasons, drilling is sometimes stopped before complete penetration of the reservoir has been achieved. Such wells are described as partially penetrating. In other cases, a well may be drilled completely through a reservoir, but only a part of the reservoir is completed for injection. Figure 5 depicts partially penetrating and partially completed wells. The equation for pressure buildup as a result of injection into (pumping from) such a well (Hantush, 1964; Witherspoon, et al, 1967) is:

$$P_r = P_i + P_{DPP}\left(\frac{141.2q\mu\beta}{\phi\mu cr^2}\right) \quad (17)$$

where:

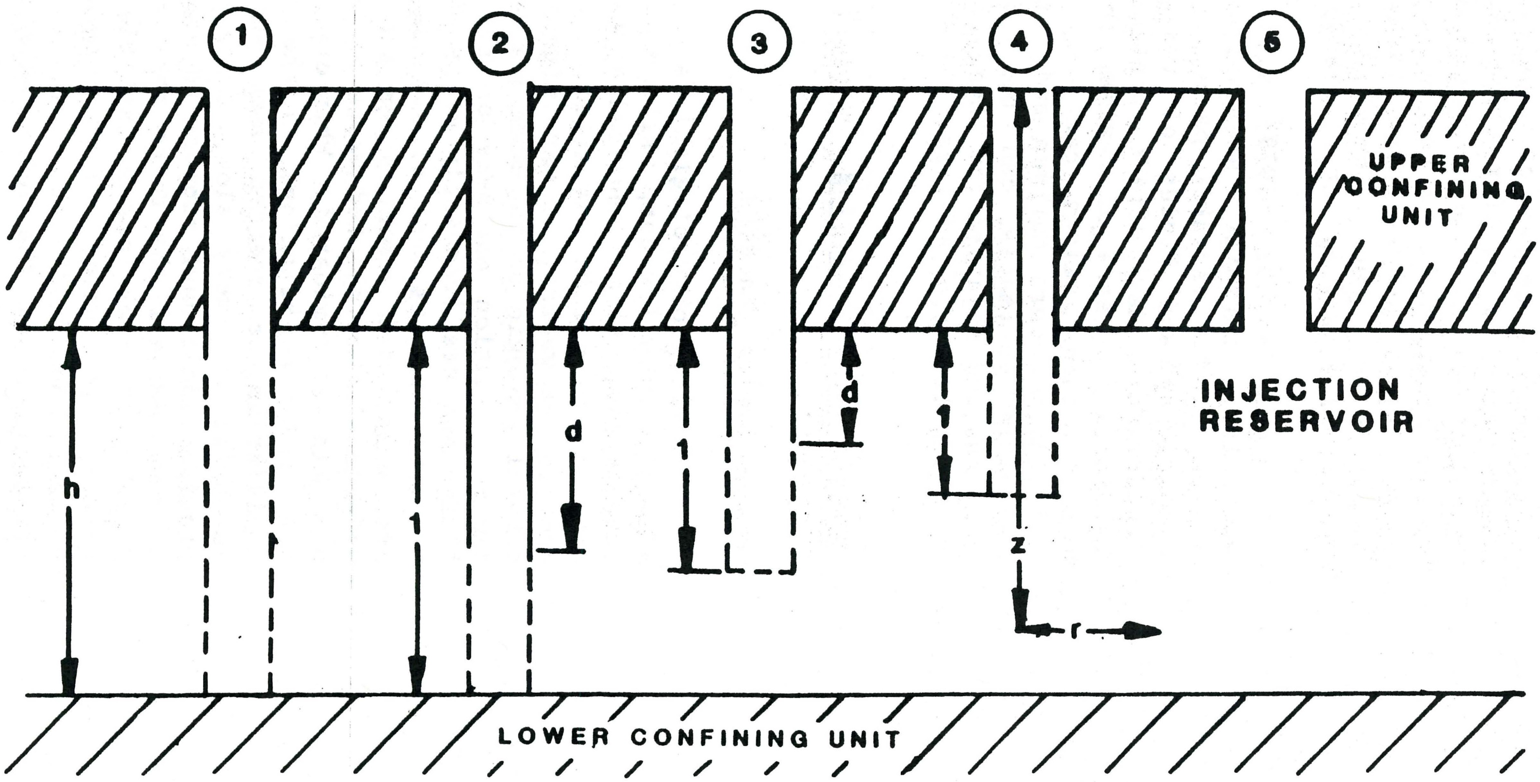
$$P_{DPP} = \frac{1}{2} [Ei \left(\frac{1}{4t_D}\right) + f(r, h, l, d, z)]$$

FIGURE 5

WELLS WITH VARYING DEGREES OF PENETRATION AND COMPLETION

1. FULLY PENETRATING FULLY COMPLETED WELL.
2. FULLY PENETRATING PARTIALLY COMPLETED WELL.
3. PARTIALLY PENETRATING PARTIALLY COMPLETED WELL.
4. PARTIALLY PENETRATING FULLY COMPLETED WELL.
5. NON-PENETRATING WELL.

(FROM WARNER, et.al. 1979)



Partial penetration results in greater pressure buildup (decline) at and near the wellbore than would be experienced in a fully penetratin well for the same injection (pumping) rate. The magnitude of differe depends on the degree of penetration, l; the ratio of the radius investigation to aquifer thickness, r/h; the length of the completed interval, l-d; and the vertical point of investigation, z. The expanded form of Equation 17 is too complex for practical use by hand and the number of variables so large that is is impractical to provide tables for evaluation of P_{DPP}. Computer programs have been developed to solve Equation 17 by Warner, et al (1979).

Warner, et al (1979) also addressed the effects of fractured reservoirs, infinite semiconfined reservoirs, bounded reservoirs, reservoirs with variable permeability, reservoirs with radially varying permeability and fluids of variable viscosity. Although all these possibilities may effect pressure buildup within a reservoir and therefore, the area of review, their specific values are rarely known. Normally these values can only be determined through well testing utilizing pressure buildup and fall off or step rate injection testing. Reasonable estimates can normally be made with the aforementioned equations and adjusted for these parameters after operating the system for a reasonable period of time.

Criteria for Eliminating Potential USDW Contamination through Geological Barriers

Geohydrological Factors

Several geohydrological factors must be considered when studying the area of review for deep well injection. The subsurface environment is a complex physical and chemical system. Before the injection of fluids into this system can be permitted, it must be evaluated for its ability to contain the wastes. Upward migration of wastes can occur through either natural geologic or man-made pathways. Natural geologic conduits such as faults, solution channels or fractures are usually filled with native fluids and are frequently sealed from USDWs by secondary mineralization. Man-made conduits such as old abandoned test holes or oil and gas wells are sealed with cement plugs and drilling muds. However, the chemical effects of the injected waste on the formation rock and conduits, if any, must also be evaluated. When evaluating these phenomena, we must remember that chemical reactions in the subsurface are normally very slow and equilibrium is reached very quickly. Since fluid movement in the subsurface is very slow, diffusion is the primary mixing factor and provides additional support to waste containment near the well bore. If we consider all the rocks that are commonly penetrated when a well is drilled, the rock most susceptible to blocking both artificial and natural conduits is shale. Both sandstones and carbonate rocks can become unstable, and fill a well bore or annular space when subjected to tectonic stresses or when the hydrostatic mud pressure is lower than the pressure on the fluids within the rocks, particularly when the permeability is low. The instability of shale, on the other hand, is compounded by the extraordinary manner that this rock is affected when exposed to water.

Reaction of Shales and Clays

Shales are essentially rocks that contain clay. Shale rocks are formed by the compaction of sediments. Water is squeezed out as sediments are buried deeper by layers deposited progressively during geologic time. The degree of compaction of the sediments is proportional to the depth of burial, provided the water is able to escape easily to permeable strata. The younger sediments soften and disperse when mixed with water. The older shales usually have undergone diagenesis, may remain hard and are less easily dispersed into water. The term shale is applied to everything from clays to lithified materials such as slate. Soft clays are extremely reactive with water while slates are relatively inert. Because the various shales behave differently upon exposure to drilling fluids when penetrated by the bit, it is useful to classify shales so that instability may be approached in a somewhat systematic manner. Such a classification is shown in Table I.

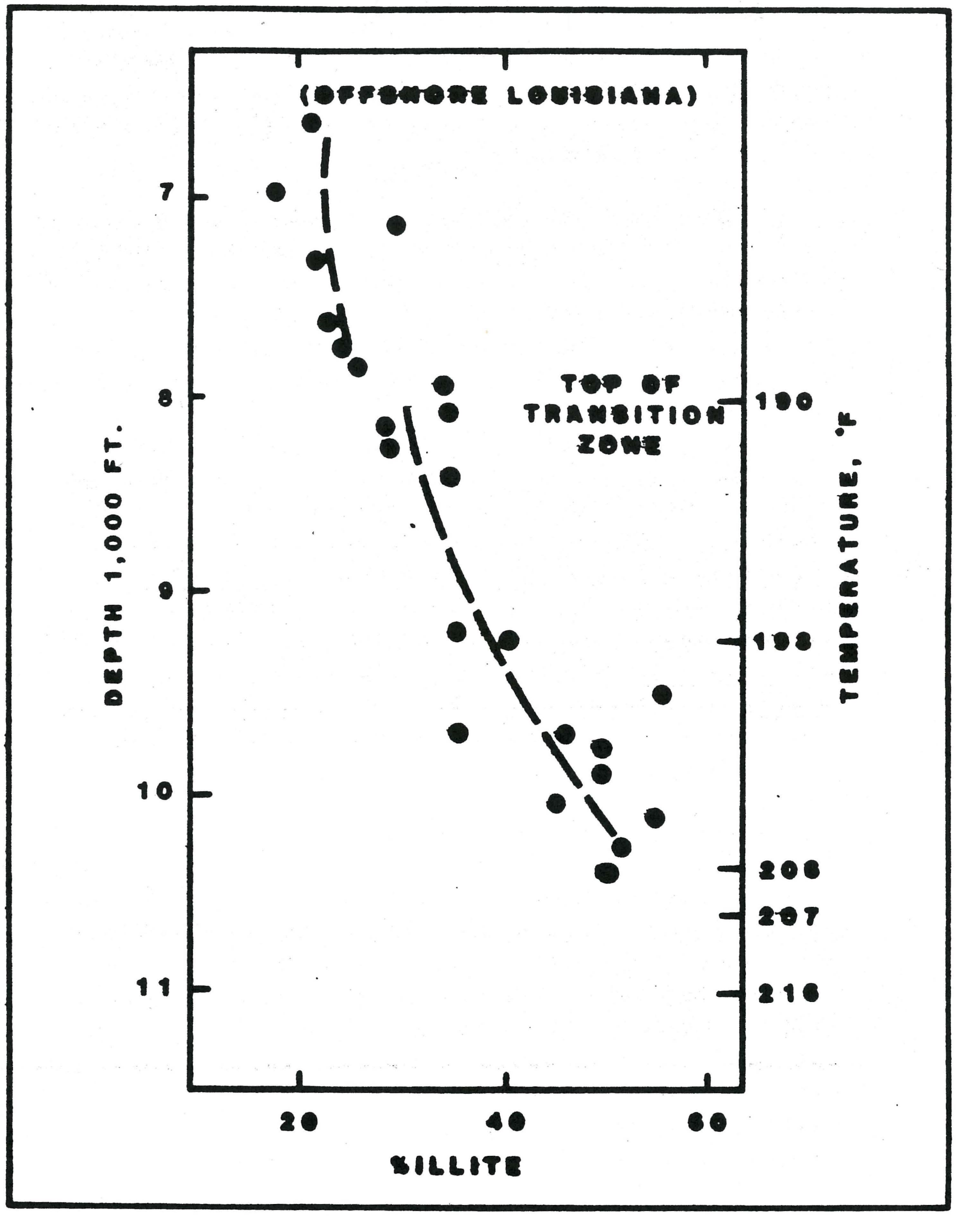
The amount of clay, the type of clay, the depth of burial, and the amount of water in a given shale all relate to the stability of the shale. The amount of clay in a given shale depends on the composition of the shale sediments at the time of deposition. The type of clay in a given shale depends not only on sediment composition at the time of deposition, but also on changes that may occur in the clay after burial.

From the view point of effect on hole stability, clays may be classified broadly as expandable and non-expandable. Expandable clays exhibit a high degree of swelling when wetted with water. Expandable clays as a group are called smectites. Montmorillonite (bentonite) is a high-swelling member of the smectite group. The non-expandable clay most commonly found in shales is illite. Chlorite and kaolinite are non-expandable clays often found in shales as well. Non-expandable clays swell much less than expandable clayes on being wetted with water. The degree of swelling of both clay types varies greatly with the type and amount of salt dissolved in the water with which the clay is wetted (R.E. Grim, 1968).

The type of clay in younger sediments depends in large part on the temperature at depth of burial. A change in clay mineralogy with depth is illustrated in Figure 6 (W.H. Fertl and D.J. Timko, 1970). The increasing percentage of illite with depth is attributable to alteration of smectite to illite. The alteration phenomenon is called "diagenesis". Some water of crystallization is released from the expandable clay during diagenesis. Illite differs from montmorillonite structurally in that some of the silicons in the outer silicate layers (R.E Grim, 1968) of illite are always replaced by aluminums, and the resultant charge deficiency is balanced by potassium ions (R.E. Grim, 1968). Temperature, rather than pressure, is thought to be the critical variable in the reaction through which this change is brought about.

The amount of water in a given shale depends on the depth of burial and the type of clay in the shale. Loosely bound water is squeezed out of the shale by pressure exerted by the weight of the overburden of the earth at depth of burial. A good approximation of the magnitide of overburden pressure is 1 psi/ft of depth. A laboratory experiement that illustrates

FIGURE 6
LATTICE MIXING
(FROM FERTLAND AND TIMKO)



this phenomenon is presented graphically in Figure 7 (H.C.H. Darley, 1969). Both bentonites in this illustration are expandable clays, and the Ventura shale contains mostly non-expandable clays. Most of the free water that can be easily squeezed out of the expandable clays is freed with a effective pressure of 2500 to 2000 psi. A matrix (grain to grain) stress of this magnitude would be expected in the crust of the earth at a depth of about 4500 to 5500 feet. Additional water is released as the swelling clays are subjected to even greater effective pressures.

Causes of Shale Instability

Shale instability may result from the following forces, either singly or in combination:

1. Overburden pressure
2. Pore pressure
3. Tectonic forces
4. Water adsorption
   a. Dispersion
   b. Swelling

Various forms of hole instability arise when the stress relief of overburden pressure occasioned by drilling exceeds the yield strength of the formation. A well-known example of this phenomenon is the plastic flow that occurs in geopressured shales. The water content and the plasticity of the shale are abnormally high relative to the overburden load, and the shale is extruded into the hole in plastic flow.

When the pressure of the drilling fluid is less than the pressure of the fluids within the pores of the rock being drilled, the pressure differential toward the hole tends to induce fragments of rock to fall into the hole. Such caving is more likely to occur when the rock is relatively impermeable. The strength of the rock is a factor in this process as well.

Tectonic forces result from stresses imposed on a given stratum by deformation of the crust of the earth. Such deformation is commonly described as folding and faulting, and is a normal result of the formation of mountains. Stresses thus created are relieved quickly in shale that is readily deformable, but tend to remain in rocks that are brittle. Even a small amount of water adsorption can cause sufficient stress to induce shales to flake off in fragments and slough into the hole.

Shale Classifications

Reference to a shale classification like the one given in Table I is helpful for a description of the effect of water absorption on shale stability. Because the number of combinations of physical and chemical properties of rocks called "shale" is so large, a classification of some kind is necessary for a logical and organized approach to predict the probability of occurrence. For purposes of illustration, a description follows of how shales of Class A through E behave upon wetting with fresh water. Obviously the behavior of the different classes of shale would be different in various salt solutions.

FIGURE 7

WATER RETAINED UDER LOAD

(FROM DARLEY)

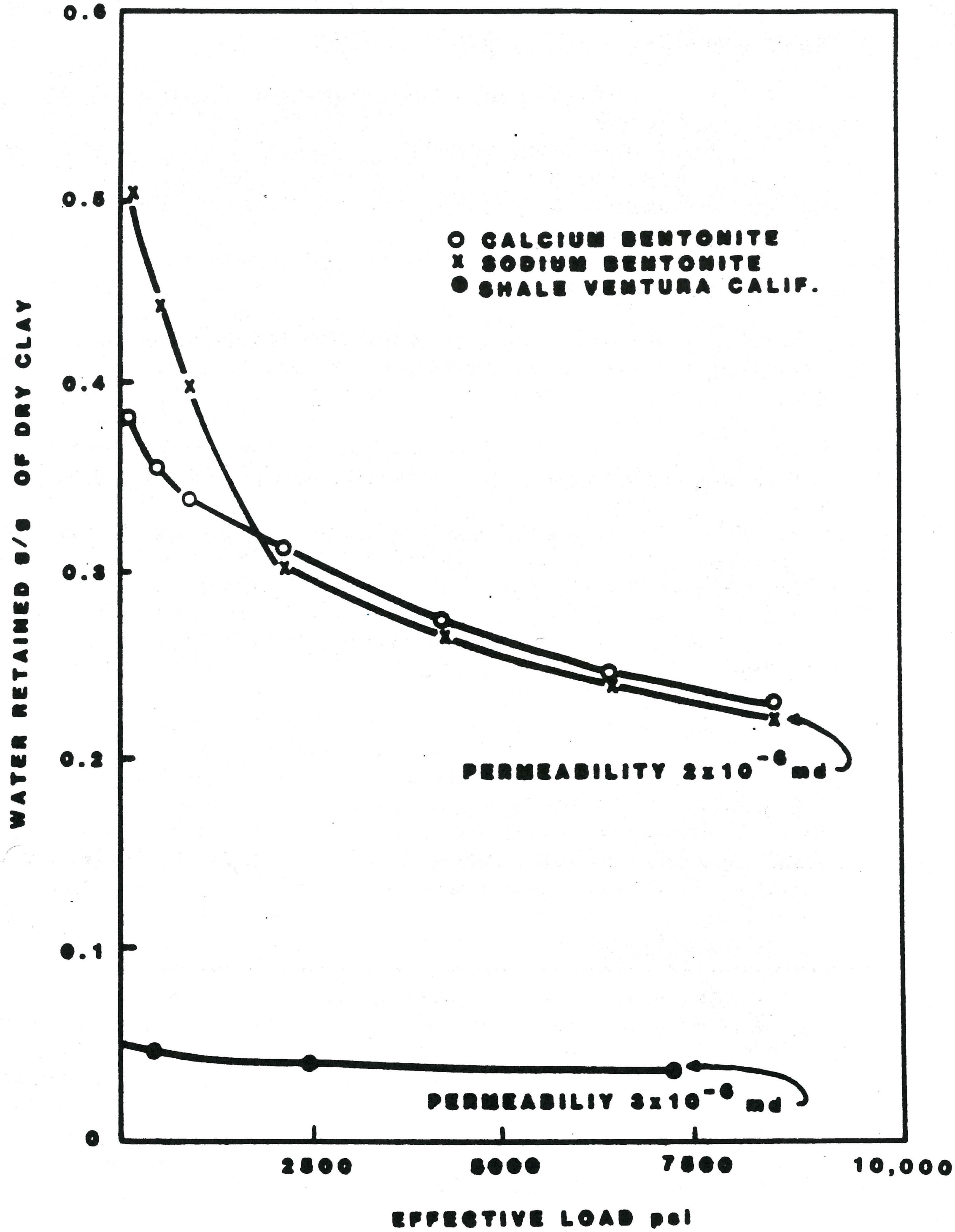


TABLE 1

A GENERAL SHALE CLASSIFICATION

Class	Texture	Methylene blue capacity (me/100g)	Water Content	Wt% Water	Clay Content	Wt% Clay	Density g/cc
A	Soft	20-40	Free and bound	25-70	Montmorillonite and illite	20-30	1.2-1.5
B	Firm	10-20	Bound	15-25	Illite and mixed layer montmorillonite-illite	20-30	1.5-2.2
C	Hard	3-10	Bound	5-15	Trace of montmorillonite high in illite	20-30	2.2-2.5
D	Brittle	0-3	Bound	2-5	Illite, kaolin chlorite	5-30	2.5-2.7
E	Firm-hard	10-20	Bound	2-10	Illite and mixed layer montmorillonite-illite	20-30	2.3-2.7

(From Mondshine 1969)

Class-A shale is characterized primarily by high-water content and relatively high expandable clay content. The word montmorillonite as used in Table I denotes expandable clays as identified by the methylene blue test. The word smectite is now a more widely accepted group name. Montmorillonite is a member of the smectite group. Shale of this quality is often found at shallow depth where the overburden load is still too small to have squeezed more water from the sediments during compaction, and the temperature too low to have induced diagenesis. The same shale may also be found at greater depth when permeable avenues for the escape of connate water did not exist, and where conditions were not right for montmorillonite to have been altered to illite (see Figure 6). When still more water is added to Class A shale, it would be expected that the compaction process would be to a degree reversed. In the higher water content range, this shale could also be squeezed into the hole from the pressure created by the weight of the overburden. The lower the mud weight, the more likely it would be for this phenomenon to occur.

Class-B shale would respond to adsorption of fresh water mainly by becoming more plastic or less firm. Water would penetrate slowly from the borehole into the shale body. Capillary adsorption of water into bedding planes would occur nominally if at all, because of the smectite clays in the shale. Abnormal pore pressure in shale of this description is possible. Aside from possible pressure effects, Class-B shale would usually remain rather stable after being penetrated.

Class-C shale would be more likely to slough into the hole than either Class A or B. This type of shale would be found in sediments similar to those that constituted Class-B shale, but at greater depth. Some softening would occur upon adsorption of fresh water. Very likely there would be sections where the shale would still be hard after water adsorption and some swelling, so that some fragments would disengage from the matrix and fall into the hole. The mechanism of fragmentation could be the result of either capillary adsorption along bedding planes, or simply penetration of water into the shale body away from the hole.

Class D shale may be found at both shallow and great depths, but is likely to be quite old geologically. Brittle shale subdivides into small particles when immersed in water, but swells and softens very little if at all. It is believed that cleavage takes place along old fracture planes that are held together by attractive forces that act over short distances only. Hydration when contacted by an aqueous drilling fluid causes separation at the old fracture planes.

Class E shales are likely to be found quite deep, and are usually abnormally pressured. Occurrence of this type of shale is sometimes thought to be anomalous, even though it is found quite often in sediments of tertiary age. This shale would have a strong tendency to slough upon adsorption of fresh water. In interbedded smectite-illite intervals, illite ledges may be borken off by the unequal degree of swelling of the two different shales.

Shale Hydration

Water wetting of shale can and usually does result in borehole blockage. The instability usually results primarily from overburden pressure, pore pressure, or tectonic stress. This is true regardless or whether the clay in the shale is largely expandable or non-expandable, or whether the shale in place is brittle or plastic. Moreover, shale disperson, hole closure or sloughing from shale swelling are all attributable to adsorption of water by shale.

The forces that cause shale to absorb water are attributable to the clay in the shale. It should also be emphasized at the outset that these forces through which clay adsorbs, imbibes, draws or sucks water into itself can be very great. By comparison the force with which mud filtrate may be pressed into the formation by the differential between the hydrostatic pressure of the mud column and the pore pressure of the formation is very small. For example, if a normally pressured stratum at 5000 or 10,000 feet on the Gulf Coast is drilled with 9.5 ppg mud, the pressure differential would be about 125 and 250 psi respectively. This figure represents the pressure with which filtrate from the mud is being pressed into the formatio by the overbalance of hydrostatic pressure over pore pressure. The text following will illustrate that the water adsorption forces of shale are much greater.

Hydration of shale depends upon a number of factors such as the hydration energy of the interlayer cations on the clays present and the charge density on the surface of the clay crystals. A reasonable estimate of the shale hydration force can be made by considering the compaction forces involved in subsurface burial of a given shale stratum during geologic time. For well drilling purposes, the hydration force is calculated conveniently in this way. The effective compaction stress on a shale section at any given depth can be represented by the equation, $s = S - P$, where s is the intergranular or matrix stress (W.R. Mathews and J. Kelly, 1967), S is the overburden pressure (approximately 1 psi/ft), and P is the pressure on the fluid in the pores of the rock.

As a given layer of shale is buried deeper, progressively more water is squeezed out of the shale by the weight of the overburden. The force with which water is being expelled from the shale in the compaction process equals the intergranular or matrix stress. The adsorption (or suction) force of the clay acts in opposition to the water expulsion force of compaction. This compacting force is relieved on the borehole face when the shale is penetrated by the bit. Consequently, a hydration force equal to the degree of relief develops. Since the compaction force equals the matrix stress, then:

$$\text{SHALE HYDRATION FORCE}_{psi} = \text{OVERBURDEN}_{psi} - \text{PORE PRESSURE}_{psi}$$

For example, assuming again a normally pressured shale (9 lb/gal mud weight equivalent) at 10,000 ft on the Gulf Coast:

$OVERBURDEN_{psi} = 1\ psi/ft = 10{,}000\ psi$

$$MATRIX\ STRESS_{psi} = OVERBURDEN_{psi} - PORE\ PRESSURE_{psi}$$

$$= 10{,}000\ psi - (9 \times 0.052 \times 10{,}000)\ psi$$

$$= 5320\ psi$$

The shale hydration force at 10,000 feet in normal pore pressure is therefore 5320 psi.

Drilling Fluids

Artificial penetrations in the area of review or zone of endangering influence can provide potential conduits to USDWs if improperly plugged when abandoned, improperly cemented when constructed or a combination thereof. Artificial penetrations are usually man-made holes used for the exploration of oil and gas or other minerals and water. These holes are rarely empty and are fluid filled with native water, brine or drilling fluid. In the case of native waters or brine the fluids may have seeped into the well bore or been left there by the original driller. If the well was originally drilled with a cable tool rig or rotary drilling rig using compressed air, the fluid in the hole is probably native water or brine. However, the vast majority of artificial penetrations are made exploring for oil and gas. Therefore, it is logical to conclude that most well bores are mud filled since rotary drilling techniques using drilling fluid are predominately used when drilling oil and gas exploration and development wells. Upon completion of the drilling operation, if the well is not completed for production, the drill pipe is removed from the well bore and the drilling mud used to drill the well will remain in the well bore indefinitely. If the well is completed or casing is run and partially cemented across a portion of the well bore, drilling mud would have been displaced ahead of the cement from the annular space between the casing and open hole. If cement was not circulated to the surface, then the annular space above the cemented section will be filled with drilling mud.

A fluid filled well bore or annular space provides resistance to upwards fluid migration because of two opposing forces. The first would be the hydrostatic head or downward force caused by the weight of the fluid column. This can be described as psi/foot of depth by taking the weight of one cubic foot of water and dividing it into 144 square inches one-foot high. A cubic foot of water weighs approximately 62.3 pounds, dividing by 144 square inches, we find that a column of water one-foot high exerts a downward pressure of 0.433 psi. Therefore a column of water 1000 feet deep would provide a downward force of 433 psi. If fluid were migrating upward, it would have to have a driving force in excess of 433 psi. This example used fresh water having a density of 8.33 lbs/gal. The second opposing force that would act as a deterent to fluid migration along a well bore would be present only if the fluid filling the well bore had gel strength. Most drilling fluids contain this characteristic.

One of the primary functions of the drilling mud is the removal of drilled cuttings from the well bore. The mud carries the cuttings from beneath the bit, transports them up the well bore/drill pipe annulus and releases them at the surface. Since normal drilling operations require that mud circulation be stopped periodically to add another joint of drill pipe, the mud must have a property which acts to suspend the drilled cuttings in the static mud column. This property is known as gel strength. Gel strength is time dependent and increases as the mud column remains quiescent. Most drilling fluids are thixotropic and develop a gel structure like "Jello" when allowed to stand quiescent but become fluid when disturbed.

To determine the combined effect of both hydrostatic head and gel strength acting as a deterrent to fluid migration along a mud filled well bore or annulus, we must first identify the forces acting on a well bore and/or annulus existing in a static state. Figure 8 represents a vertical force diagram of a static mud column in an abandoned well that contains no uncemented casing. Figure 9 represents the forces acting on the static mud column in the annulus between the casing and open hole above the cemented interval.

The equation for the force balance in Figure 8 takes the following form,

$$w + GS_w\left(2\pi r_w h\right) = P_f\left(\pi r^2{}_w\right) - P_t\left(\pi r^2{}_w\right) \qquad (18)$$

where

$$w = r^2{}_w \rho h$$

and

w = weight of mud column
GS_w = gel strength of mud column acting on circumference area of well bore
P_t = pressure at top of well
P_f = pressure at formation being contained
r_w = radius of well bore
h = height of mud column in well bore
ρ = density of mud

Simplifying the force balance and adjusting for standard units, we obtain the following pressure equation,

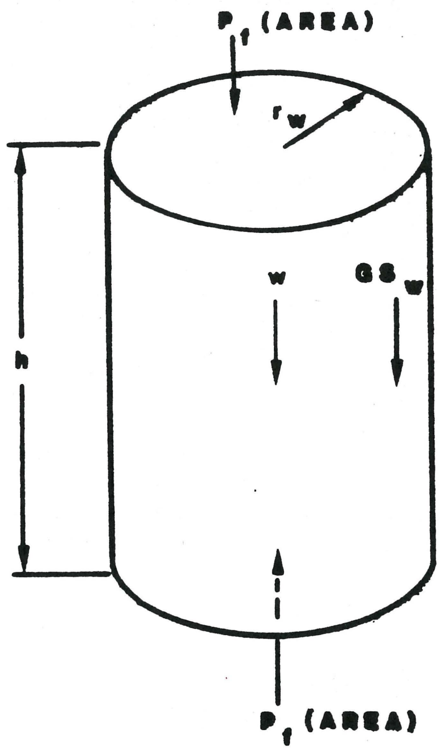
$$P_f = P_t + 0.052\rho h + 3.33 \times 10^{-3} GSh/D \qquad (19)$$

where:

P_f = pressure at the contained formation in psi
P_t = pressure at the top of well
ρ = density of mud in lb/gal
h = height of mud column in feet
GS = gel strength in lb/100 ft^2
D = diameter of well bore in inches

FIGURE [illegible]

STATIC MUD COLUMN
FORCE BALANCE DIAGRAM



P_t (AREA) = PRESSURE AT THE TOP OF WELL = $P_t \pi r_w^2$

W = WEIGHT OF FLUID COLUMN $\rho h \pi r_w^2$

GS_w = GEL STRENGTH OF MUD ACT[illegible] ON CIRCUMFERENCE AREA OF WELL BORE = $GS_w (2 \pi r_w h)$

P_f (AREA) PRESSURE AT THE FORMATION BEING CONTAINED $P_f \pi r_w^2$

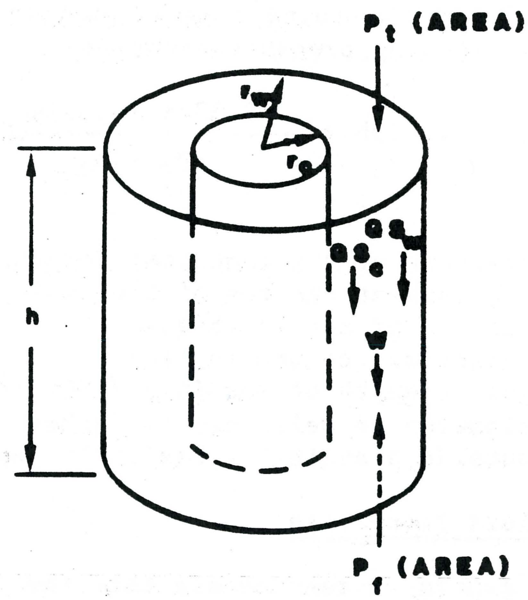
FORCES FROM MUD COLUMN SUM OF PRESSURE FORCES

$$w + GS_w (2\pi r_w h) = P_f (\pi r_w^2) - P_t (\pi r_w^2)$$

FIGURE 9

ANNULUS STATIC MUD COLUMN FORCE BALANCE DIAGRAM

WELLBORE ANNULAR EFFECTS



FORCES FROM MUD COLUMN = SUM OF PRESSURE FORCE

$$W + GS_c(2\pi r_c h) + GS_w(2\pi r_w h) = P_f \pi (r_w^2 - r_c^2) - P_t \pi (r_w^2 - r_c^2)$$

The force balance equation for **Figure 2** takes the form

$$w + GS_c(2\pi r_c h) + GS_w(2\pi r_w h) = P_f\pi(r^2_w - r^2_c) - P_t\pi(r^2_w - r^2_c) \qquad (20)$$

where

$$w = \rho h(r^2_w - r^2_c)$$

and

w = weight of mud column in annulus
GS = gel strength of mud acting on circumference area of both the well bore (GS_w) and casing wall (GS_c) and $GS_w = GS_c$
P_t = pressure at top of well
P_f = pressure at formation being contained
r_w = radius of well bore
r_c = outside radius of casing
h = height of mud column in annulus
ρ = density of mud

Simplifying the force balance and adjusting for standard units, we obtain the following pressure equation,

$$P_f = P_t + .\text{[illegible]}\rho h + \frac{3.33 \times 10_{-3} GSh}{D_w - D_c} \qquad (21)$$

where:

P_f = pressure at the contained formation in psi
P_t = pressure at the top of the well
ρ = density of mud in lb/gal
h = height mud column in feet
GS = gel strength of mud in lb/100 ft^2
D_w = diameter of well bore in inches
D_c = outside diameter of casing in inches

Drilling Fluid Properties

It is generally recommended that the values required to calculate the flow resistance of a mud filled well bore or annular space be obtained from the well records. The physical configuration of the well can usually be obtained from many sources. These include but are not limited to state and federal permit records, the owner/operator files, commercial libraries, geological surveys and other public information sources. The density of the drilling fluid used to drill the well is normally recorded on the geophysical log heading as shown in Exhibit 1. The gel strength values may be more difficult to obtain. Mud properties are generally run while conditioning the mud to run casing and cement. These values are normally determined by the drilling fluid supplier or service company and are reported on standardized forms such as the one shown in Exhibit 2. These data are normally available from the owner/operator's well files or the service company. Also, it is frequently not necessary to find t

EXHIBIT 1

Schlumberger

BOREHOLE GEOMETRY LOG

COUNTY
FIELD or LOCATION
WELL
COMPANY

COMPANY ____________________

WELL ____________________

FIELD ____________________

COUNTY ____________ STATE ____________

LOCATION

Sec. ________ Twp. ________ Rge. ________

Other Services:

Permanent Datum: ____________, Elev. ________
Log Measured From ________, ____ Ft. Above Perm. Datum
Drilling Measured From ____________

Elev.: K.B. ________
D.F. ________
G.L. ________

Date				
Run No.				
Depth—Driller				
Depth—Logger				
Btm. Log Interval				
Top Log Interval				
Casing—Driller	@	@	@	@
Casing—Logger				
Bit Size				
Type Fluid in Hole				
Fluid Level				
Dens. Visc.				
pH Fluid Loss	ml	ml	ml	ml
Source of Sample				
R_m @ Meas. Temp.	@ °F	@ °F	@ °F	@ °F
R_{mf} @ Meas. Temp.	@ °F	@ °F	@ °F	@ °F
R_{mc} @ Meas. Temp.	@ °F	@ °F	@ °F	@ °F
Source: R_{mf} R_{mc}				
R_m @ BHT	@ °F	@ °F	@ °F	@ °F
Time Since Circ.				
Max. Rec. Temp.	°F	°F	°F	°F
Equip. Location				
Recorded By				
Witnessed By				

EXHIBIT 2

WELL HISTORY

Magcobar

DRILLING FLUID SERVICES

Section	1
Township	T20S
Range	R36E
Mud Type	Salt Gel- Mylogel
Spud Date	2/29/80
County/Parish	Lea
State	New Mexico

Casing	Depth	Bit Size	No.
Surface 8 5/8	1204	12¼	1
Production 7	3750	8 3/4	3

DATE	DEPTH	MUD WT	VIS SEC	FLOW LINE TEMP °F / °C	PV	YP	GELS 0/10	pH	API FLUID LOSS	HTHP FLUID LOSS	P_f	M_f	SALT OR CHLORIDE	CALCIUM	SAND %			OIL %						PAPER	LIME	SALT GEL	MYLOGEL	DAILY COST	TOTAL MUD COST
1980																													
3/1 DRILLING	1049	8.8	50				/	9					2000	2000	0						16			2	1	Tons	6 Tons	314.96	314.96
3/3 DRILLING	1877	10.3	28				/	8.5			.1	.8	150,000	2000	4						3			7	16			243.81	558.77
3/4 DRILLING	2906	10.1	28				/	9			.2	1	160,000	2000	3													-0-	558.77
3/5 DRILLING	3202	10.1	30				/	9			.2	1	160,000	2000	3													-0-	558.77
3/6 DRILLING	3543	10.1	30				/	9			.2	1	160,000	2000	3									10				304.08	862.85
3/7 LOGGING	3750	10.2	34		6	3	2 / 3	9	15		.2	.8	160,000	2000	3									10		118	31	1737.27	2600.12
																										FINAL WAREHOUSE COST			3244.51

well records of each well since wells drilled adjacent to each other frequently use the same or similar mud systems. Historical records are also a good source of obtaining conservative values for gel strengths of specific types of drilling fluid systems.

Since the gel strength of different types of mud systems varies, it is difficult to determine the exact gel strength of the mud in a particular well bore. A review of the gel strength characteristics of various types of muds was made to evaluate the factors that effect the gel strength structure. The aim of this review was to provide sufficient information to determine the minimum gel strength structure that could be anticipated for any combination of formation, well bore and mud type. This value can then be used if insufficient data is available for a specific well bore.

Thixotropy is the property, exhibited by certain gels, of liquifying when stirred or shaken and then returning to their gelled state when allowed to stand quiescent. This property in drilling fluids is the result of various clay minerals being used as additives in drilling fluids. Generally, clay particles fall into the colloidal particle range. Colloidal systems used in drilling fluids include solids dispersed in liquids and liquid droplets dispersed in other liquids. These highly active colloidal particles comprise a small percentage of the total solids in drilling muds but act to form the dispersed gel forming phase of the mud that provides the desired viscosity, thixotropy and wall cake properties.

Clay particles and organic colloids comprise the two classes of colloids used when mixing drilling fluids. The common organic colloids include starch, carboxycelluloses and polyacrylomine derivatives.

Barker (1981) reported that, "The clay colloids utilized in common drilling fluids are characterized by a crystalline structure which influences the ability of the clay to retain water." Clays used in fresh water muds consist of hydrated alumnosilicates comprised of alternate plates of silica and aluminum to form layers of each mineral. The plate-like crystals have two distinct surfaces: a flat face surface and an edge surface. Slight surface polarities induce weak electrostatic forces along the faces and edges of the mineral plates. Garison (1939) noted that these electrostatic forces attract planer water to the colloidal particles forcing the clays to swell when wet and shrink when dry. The attraction of planer water to the faces of the plates is greater than the attraction of the sheets for each other therefore the structure tends to swell due to the absorbsion of the planer water from the drilling fluid. The bentonite clays demonstrate a strong ability to attract planer water as a result they experience extreme swelling. When in contact with fresh water, the face to face attraction of water by the mineral layers will continue until the swelling reduces the attraction of the plates to the point where they separate. This separation results in a higher number of particles and is referred to as dispersion. The dispersion causes the colloidal suspension to thicken. The degree of thickening depends on the electrolytic content, salt concentration of the water, time, temperature, pressure, pH, the exchangeable cations on the clay, and the clay concentration.

Gel Strength, The Measure of Thixotropy

Thixotropy is essentially a surface phenomenon which is characterize by gel strength measurements. The gel strength indicates the attract forces between particles under static conditions. The strength of the gel structure which forms under static conditions is a function of the amount and type of clays in suspension, time, temperature, pressure, Ph, and the chemical treating agents used in the mud. Those factors which promote, the edge-to-edge and face-to-edge association of the clay particles defined as flocculation increase the gelling tendency of the mud and those factors which prevent the association decrease the gelling tendency.

Due to their size, colloidal particles remain indefinitely in suspension. When suspended in pure water the clay particles will not flocculate. When flocculation occurs the particles form clumps or flocs. These loosely associated flocs contain large volumes of water. If the clay concentration in the mud is sufficiently high, flocculation will cause formation of a continuous gel structure instead of individual flocs.

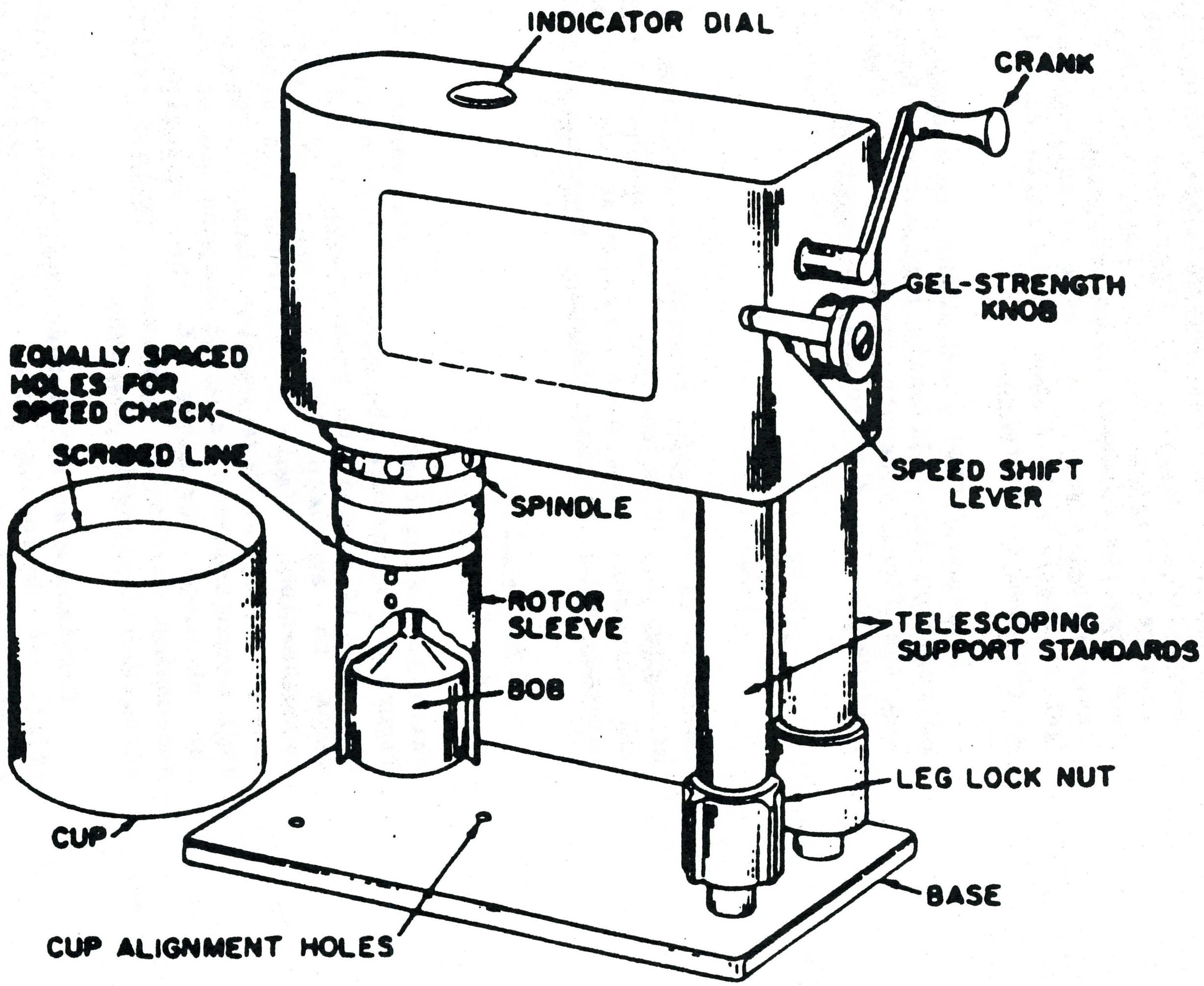
The gel structure commonly observed in aqueous drilling fluids results from salt contamination. Soluable salts are usually present in sufficient quantities to cause at least a mild flocculation. The time required for the gel to attain an ultimate strength depends on the critical concentration of electrolyte required to initiate flocculation, the thinners present, and the concentration of the clay and of the salt present. During drilling the presence of salts and clay particles varies with each formation being drilled, therefore the drilling fluid is monitored and adjustments are made in order to maintain the desired strength.

Gel Strength of the Static Mud Column

Gel strength is measured by a multispeed direct indicating viscometer (See Exhibit 3) by slowly turning the driving shaft by hand and observing the maximum deflections before the gel structure breaks. The gel strength is normally measured after quiescent periods of 10 seconds (initial gel strength) and 10 minutes. The measurements are taken at surface conditions of standard temperature and pressure. To determine the gel strength of the static mud column in an abandoned well it is necessary to determine the gel strength of the mud under the influence of borehole conditions. The initial and 10 minute gel strengths bare to direct relation to the ultimate gel strength of the mud at borehole conditions. To determine the ultimate gel strength of a mud it is necessary to discuss the factors which act to influence the initial gel strength at borehole conditions.

Once the drilling operation is completed and the well is abandoned the mud is subjected to conditions vastly different from those encountered at the surface. In the range of formation depths utilized for disposal of industrial wastes the temperature would be expected to range from 80 to 300°F, the pressure from 1500 to 5000 psi and time from days to several years. Several studies have been conducted to determine the impact of time, temperature and pressure on the gel strength of muds at bo

EXHIBIT 3
HAND VISCOMETER



conditions. The information obtained from this research should provide a means of determining a reasonable minimum gel strength value for abandoned wells which exist in the range of formations described abov

It is observed that common use water base muds develop high gel strengths after prolonged periods of quiescence. The relationship between gel strength and time varies widely from mud to mud, depending on the composition, degree of flocculation, temperature, pH, solids, and pressure. Figure 10 (G.D. Gray, H.C. Darley and W.F. Rogers, 1980) indicates the increase in gel strength with time for various mud types and reveals that there is no well established means of predicting long term gel strengths with time. It is noted in all cases that the gel strength is observed to increase.

Garrison (1939) studied the gel strength in relation to time and rate of reaction for California bentonites. He observed that both the speed and the final strength increased with the bentonite percentages. The gelling was found to follow the equation:

$$S = \frac{S'kt}{1+kt} \qquad (22)$$

where S is the gel strength at any time t, S' is the ultimate gel strength, and k is the gel rate constant. Figure 11 indicates that the gel strength forms more rapidly at first then gradually approaches an ultimate value as time elapsed. Equation 22 may be rewritten as:

$$\frac{t}{S} = \frac{t}{S'} + \frac{1}{S'k}$$

which indicates that a plot of t/S verses t should be a straight line. Figure 11 represents the graph of t/S versus t, and indicates the slope of the line is k and the y-intercept is 1/S'k. This approach provides a means to evaluate the ultimate gel strength for each bentonite concentration. Table 2 represents the ultimate gel strengths and rate constants for the five samples shown in Figures 11 and 12. Garrison also made measurements on similar suspensions at higher pH and determined that the ultimate strengths of the bentonite gels increased with each suspension as the pH increases. Table 3 reflects the pH - ultimate gel strength relationship observed.

Garrison also noted that the treating of muds with thinners had the effect of decreasing the rate of gelling but not the ultimate gel strength. Thus it can be concluded that the reduced initial and 10 minute gel strength will not be any less than that recorded for an untreated sample of the same mud. In fact, the ultimate gel strength may even increase as indicated in Table 2.

Garrison's work does not indicate that all muds comply with Equation 22, but it does point out that the initial and 10 minute gel strengths do not provide a reliable means of predicting the ultimate gel strength. Weintritt and Hughes (1965) conducted progressive gel strength tes

FIGURE 10

INCREASE IN GEL STRENGTH OF VARIOUS MUD TYPES WITH TIME (FROM GRAY, DARLEY, AND ROGERS)

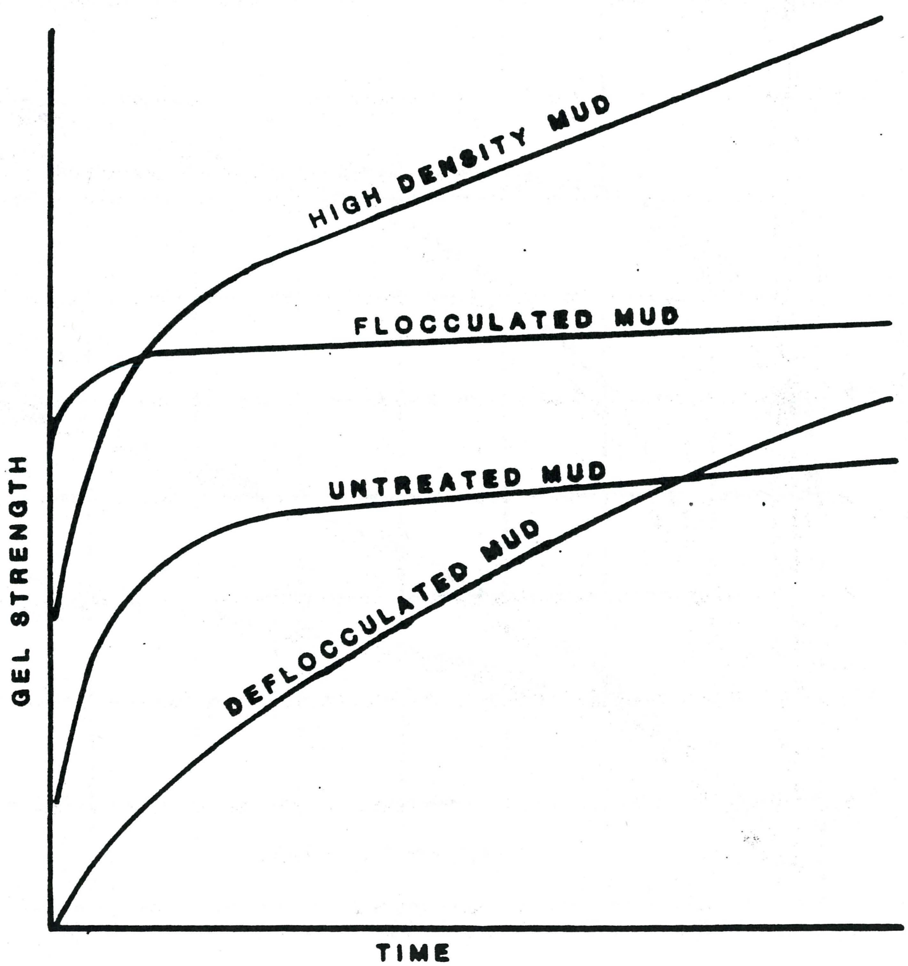


FIGURE 11
GEL STRENGTH IN RELATION TO TIME AND RATE OF REACTION
(FROM GARRISON 1939)

SEE TABLE 2

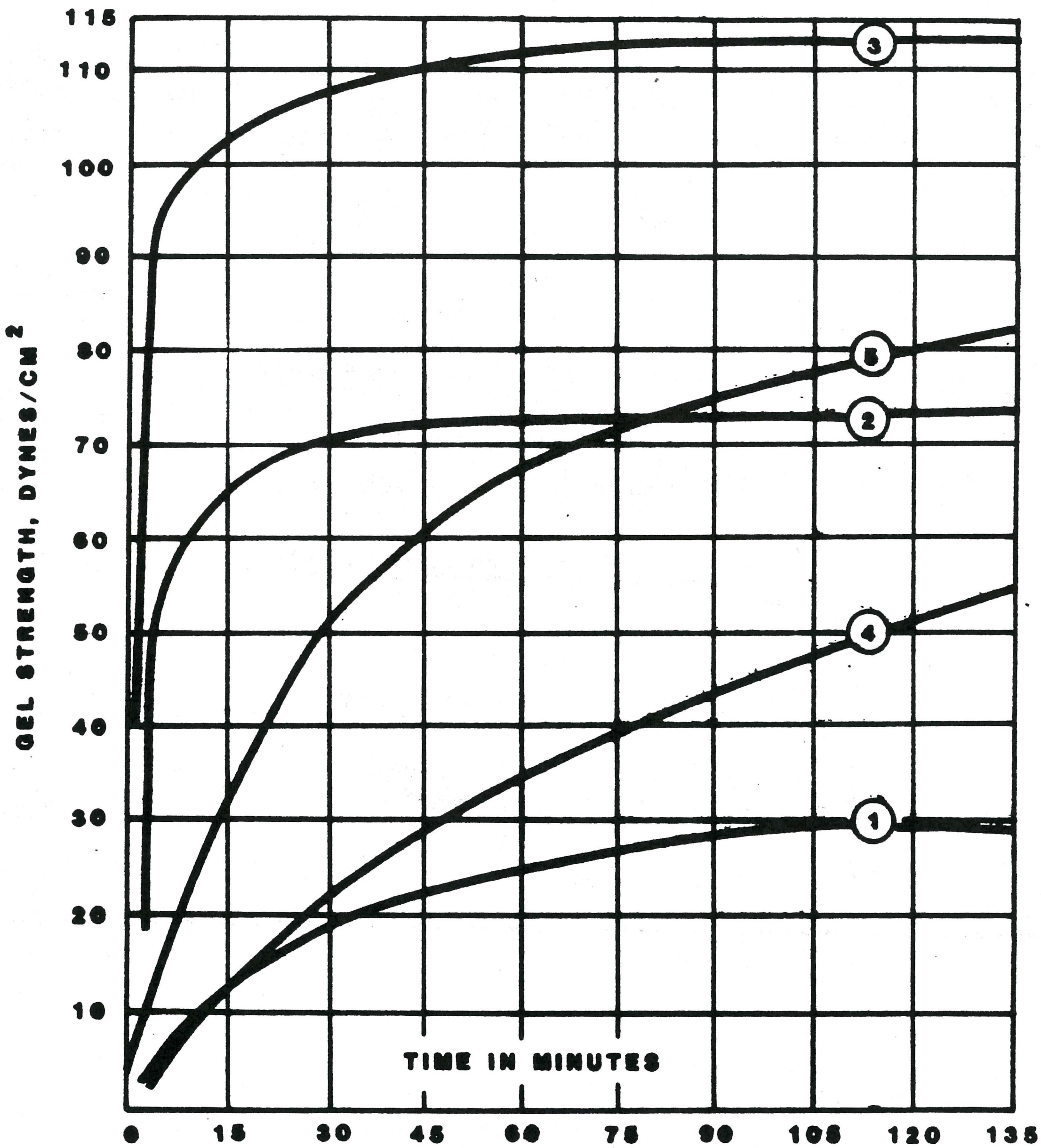


FIGURE 12

GEL STRENGTH AND RATE CONSTANTS
(FROM GARRISON 1939)
SEE TABLE 2

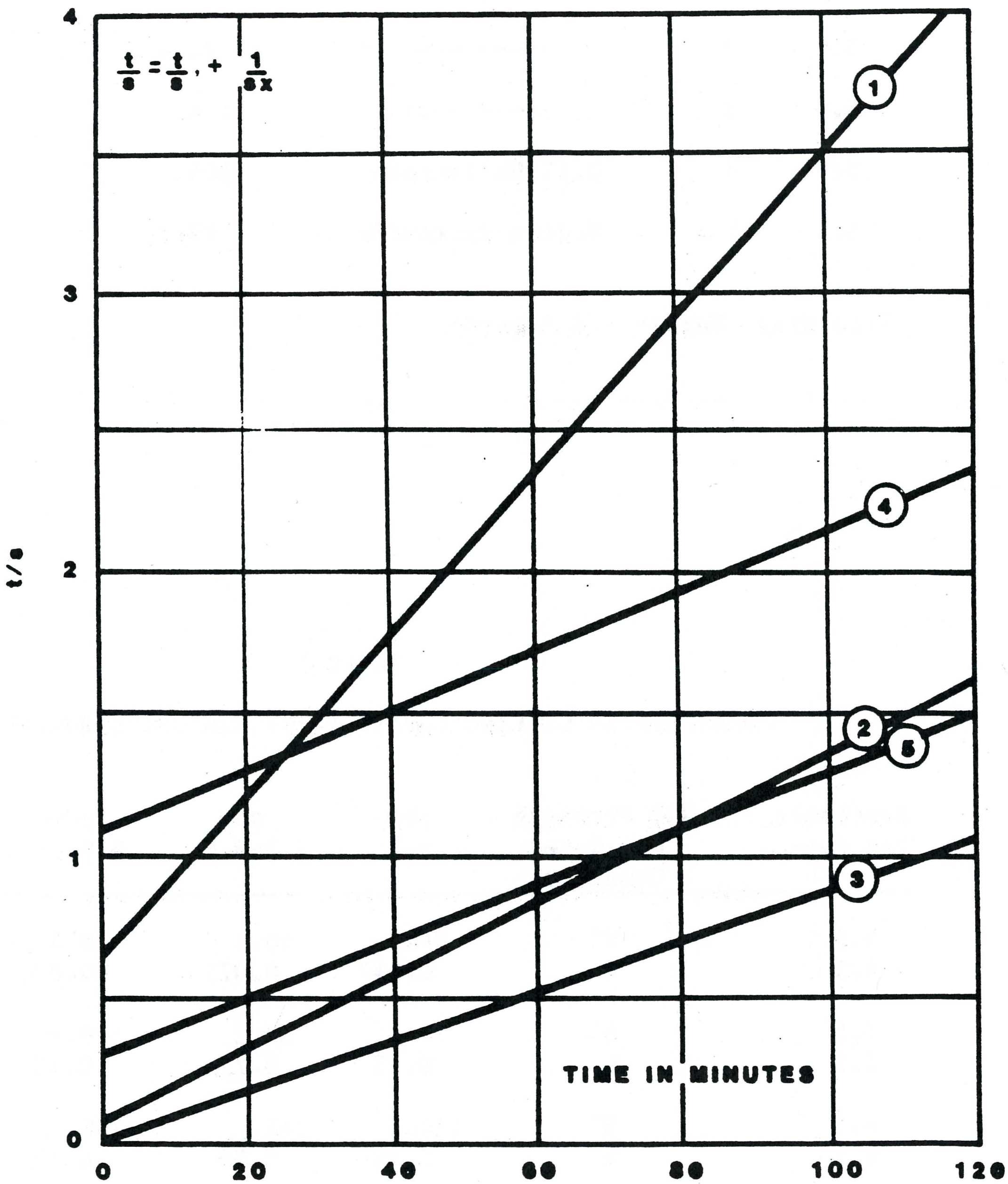


TABLE 2

GEL RATE CONSTANTS CALCULATED FROM FIGURES 11 AND 12

Bentonite Per Cent	Sample #	Additives	Gel Strength (Ultimate)	Rate Constant
4.5	1	---------	34.4	0.047
5.5	2	---------	74.4	0.75
6.5	3	---------	114.	0.79
5.5	4	0.1% Na Tannate	104.	0.0089
5.5	5	Sodium Hydroxide	99.7	0.033

(From Gray, Darley and Rogers)

TABLE 3

CONSTANTS IN GELLING EQUATIONS OF BENTONITE SUSPENSIONS

Bentonite Per Cent	Gel Strength and Rate Constant	pH+ 9.2	pH+ 9.3-9.5	pH+ 9.9-10	pH+ 10.8-11
4.5	S′	34.4	40.1	48.5	69.6
4.5	k	0.047	0.071	0.076	0.063
5.5	S′	74.4	32.2	129.9	152.7
5.5	k	0.75	0.22	0.13	0.18
6.5	S′	114.	141.	250.	268.
6.5	k	0.79	0.30	0.10	0.25

(From Garrison 1939)

ferrochrome lignosulfonate muds for periods up to 16 hours and obtained the results presented in Table 4. They noted that although Mud E and Mud F had similar properties, Mud F developed only a moderate gel strength while that of Mud E was much greater. Once again it is observed that the initial gel strength and 10 minute gel strength measurements are not always indicative of gel strength development which is observed at elevated temperatures and extended time. The three muds designated in Table 4 were obtained from wells within the same field just prior to cementing operations.

Annis (1976) noted that when a bentonite mud is quiescent, the gelling process depends on both temperature and time. Annis compared the effect of temperature on the initial and 30 minute gel strength of an 18 ppb bentonite suspension. Figure 13 indicates that the 30 minute gel strength of the 18 ppb suspension is at any temperature approximately six times the initial gel strength. The dependence of gel strength on time at different temperatures, as noted by Annis, is shown in Figure 14. Based on these and other tests of up to 18 hours Annis concluded that there is a strong indication that gel strength increases indefinitely with time.

Conclusion

In review, the above works indicate that the ultimate gel strength of water base muds is considerably higher than the values recorded for the initial and 10 minute gel strength. Although there is no direct relationship between gel strength and time, it is possible, based on available information, to conclude that the ultimate gel strength of a mud will be several times larger than the initial or 10 minute gel strength of the mud. In reference to the work by Garrison (1939), it is possible to consider the ultimate gel strength of a treated mud to be equivalent to that of a similar mud that was not treated, since the effect of the thinner is to decrease the rate of gelling and not the ultimate gel strength obtained.

In addition to time, temperature can have a major effect on the gel strength of water based drilling fluids. Srini-Vasan (1957) studied the effects of temperature on the gel strength of several water based drilling muds. Table 5 lists the muds which were tested and Figures 15 and 16 indicate the temperature versus gel strength relationships obtained. In most of the cases investigated by Srini-Vasan it was noted that the gel strength leveled off after 160°F. The emulsion and lime treated muds showed no change in gel strength with increase of temperature. It was found that each mud had its own characteristic curve and no quantitative interpretation was possible. The work of Weintritt and Hughes (1965) as noted in Table 4, indicates that emulsion Mud G experienced no change in gel strength in going from 75 to 180°F over a wide range of times. It is noted that although the gel strength did not vary with temperature, it went from an initial gel strength of 0 to a gel strength of 25 after 16 hours.

The equipment utilized by Srini-Vasan restricted his investigation to temperatures up to 220°F.

TABLE 4

COMPARISON OF MUD PROPERTIES WITH PROGRESSIVE GEL-STRENGTH TESTS GYP-FERROCHROME LIGNOSULFONATE EMULSION MUDS

	SAMPLE			
	Mud E	Mud F	Mud G	
			No Treatment	3 lb/bbl PCL
Weight, unstirred, lb/gal	11.0	10.7	10.6	
Weight, stirred, lb/gal	11.0	10.3	10.7	
Plastic Viscosity, cp	14	23	16	15
Yield Point, lb/100 sq ft	3	6	2	1
10-sec gel, lb/100 sq ft	1	2	1	0
10-min gel, lb/100 sq ft	8	8	7	3
API filtrate, sl	6.2	3.3	5.2	2.9
pH	10.9	10.6	10.5	10.4
Composition: Water, % by vol	76	63	75	
Oil, % by vol	5	11	9	
Solids, % by vol	19	16	16	
Solids, % by wt	39	36	37	
Solids, SG	2.7	2.9	3.0	

Filtrate Ion Analysis:			
Chlorides ppm	3500	400	3000
Sulfate, epm	250	300	130
Carbonate, epm	24	28	12
Bicarbonate, epm	12	160	12
Calcium, epm	44	52	44

Progressive Gel Strengths lb/100 sq ft	Temperature (°F)							
Time	75°	180°	75°	180°	75°	180°	75°	180°
0 minutes	1	1	2	2	1	1	0	0
3 minutes	2	3	2	5	3	8	1	1
10 minutes	8	18	8	12	7	26	3	3
30 minutes	15	40	11	18	17	58	5	5
60 minutes	27	90	18	16	29	91	6	6
2 hours	31	145	22	22	29	104	7	7
4 hours	37	190	29	42	46	172	10	10
8 hours	46	190	33	42				
16 hours	80	320	40	57	95	320	25	25

(From Weintritt and Hughes 1965)

FIGURE 13

EFFECT OF TEMPERATURE ON INITIAL AND 30-MINUTE GEL STRENGTH (FROM ANNIS 1976)

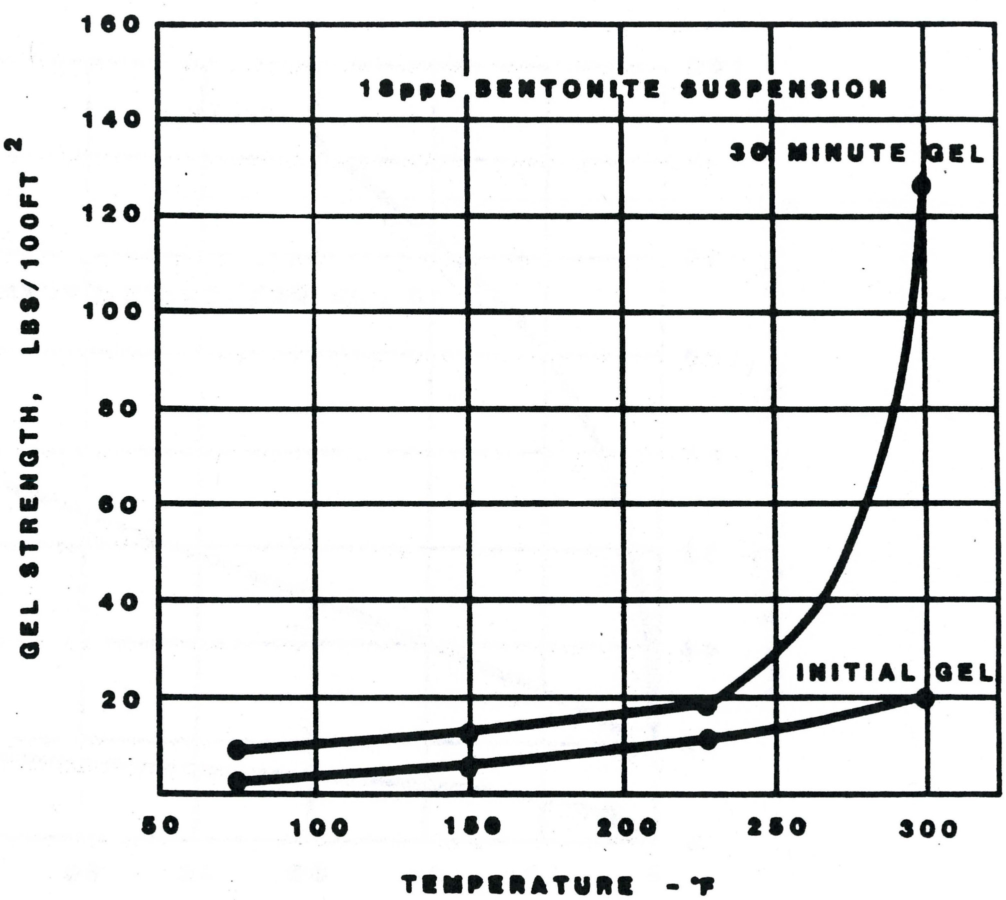


FIGURE 14
EFFECTS OF TIME AND TEMPERATURE
ON GEL STRENGTH
(FROM ANNIS 1976)

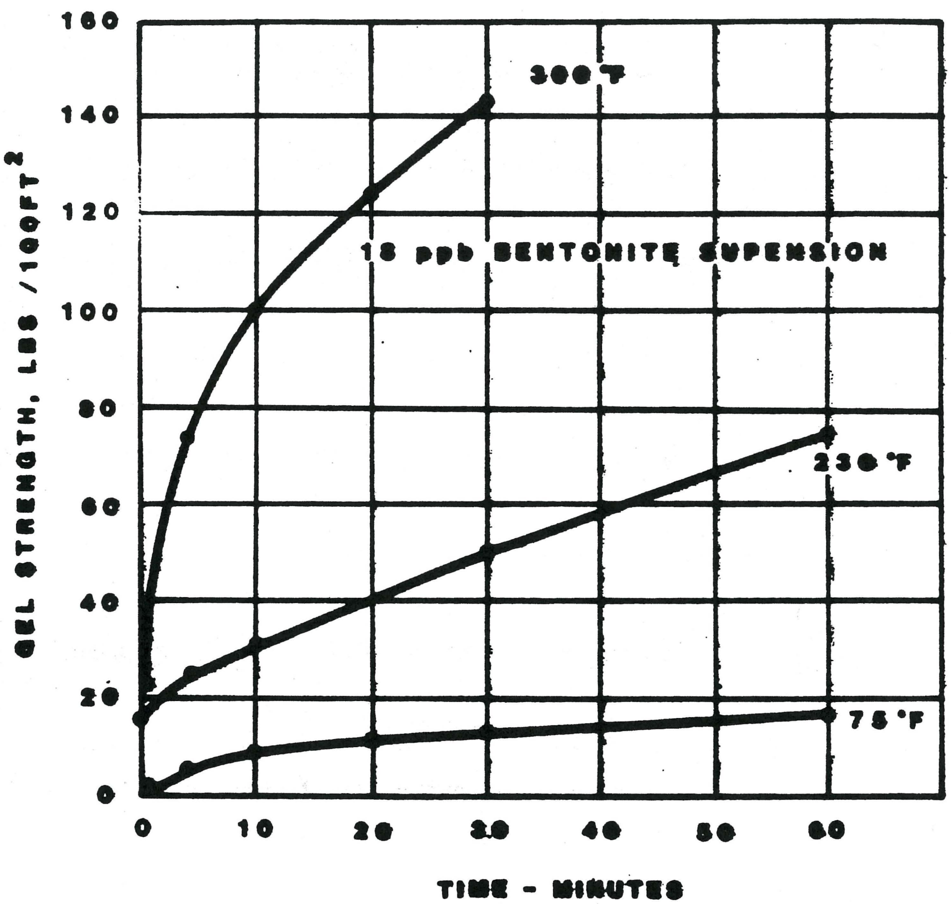


TABLE 5

COMPOSITION OF THE MUD SAMPLES TESTED FOR GEL STRENTGH

SAMPLE NUMBER	COMPOSITION OF THE MUD**
33	2 per cent bentonite mud
34	3 per cent bentonite mud
35	4 per cent bentonite mud
39	10 lb/gal, 4 per cent bentonite, barite mud
43	10 lb/gal, 10 per cent (by volume) Diesel oil, 4 percent bentonite, barite, emulsion mud
47	10 lb/gal, 4 per cent bentonite, barite, surfactant (DMS) mud
49	10 lb/gal, low lime (1 lb/bbl) treated, 4 per cent bentonite, barite mud

**All muds referred to are water base muds.
All per cent quantities mentioned denote weight per cents, unless otherwise designated.

(From Srini-Vasan)

TABLE 6

GEL STRENGTH OF A 4 PERCENT SUSPENSION OF PURE SODIUM MONTMORILLONITE TO WHICH AN EXCESS OF 50 MEQ/LITER OF NaOH HAS BEEN ADDED, MEASURED AT VARIOUS TEMPERATURES AND PRESSURES

t(°F)	P(psi)	Gel Strength (lb/100 sq ft) 1 min	10 min	30 min
78	300	2.2	--	35.0
	8000	2.2	--	7.0
212	300	18.0	26.0	40.0
	8000	9.0	9.0	15.0
302	300	240.0	290.0	265.0
	8000	88.0	100.0	100.0

(From Hiller 1963)

FIGURE 15
GEL STRENGTH VERSUS TEMPERATURE FOR
BENTONITE-WATER MUDS (FROM SRINI-VASAN 1957)

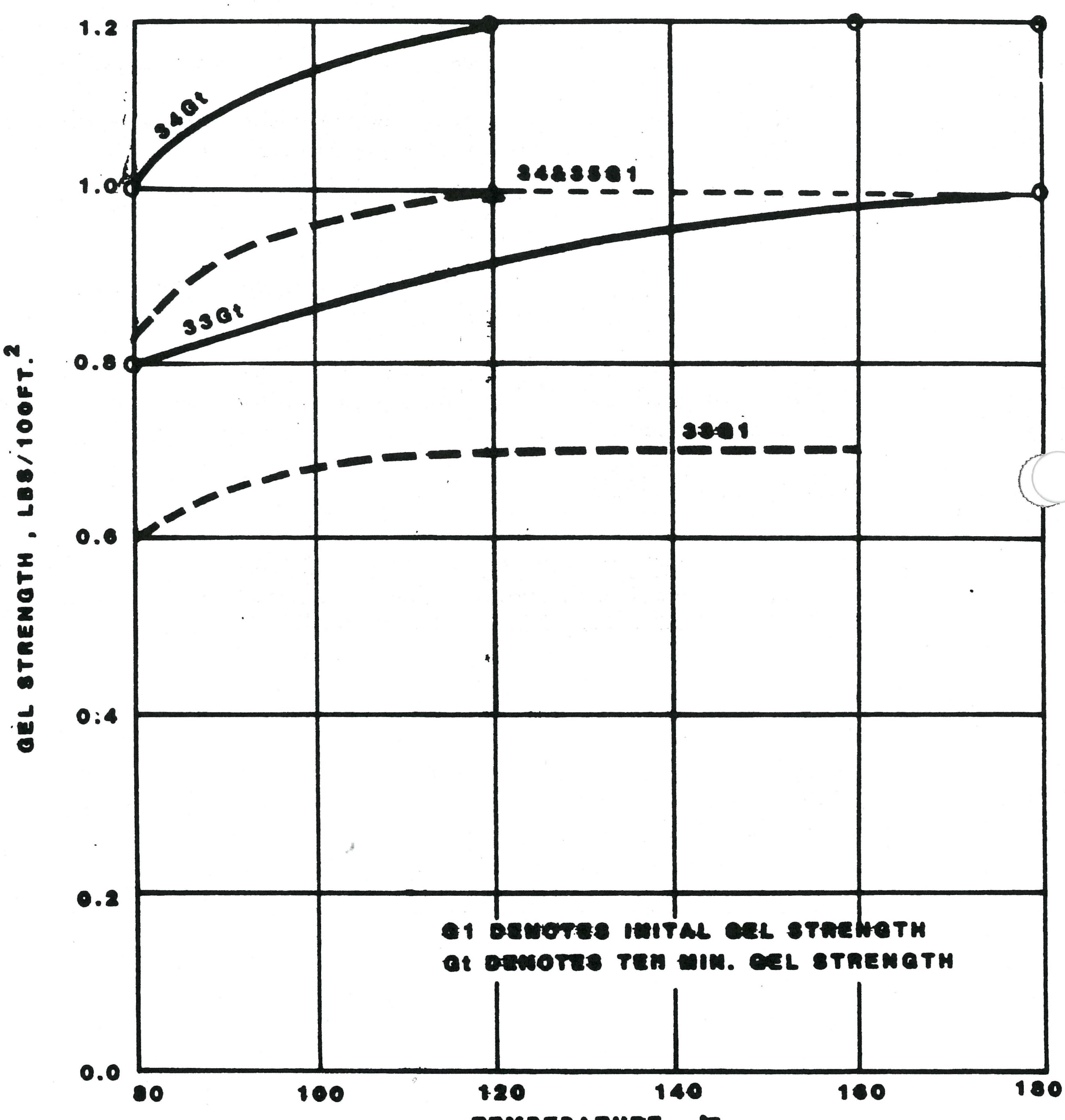
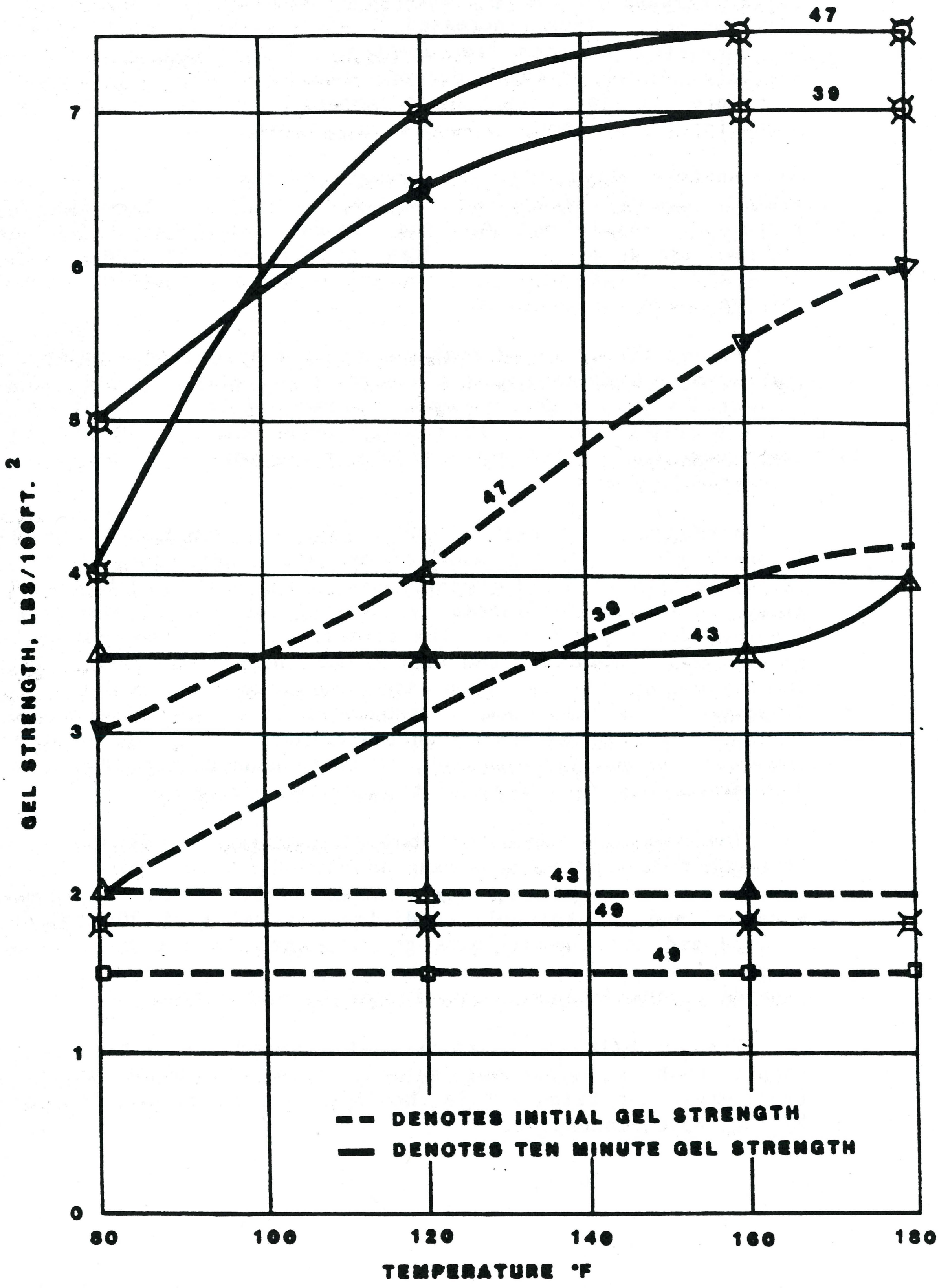


FIGURE 16
GEL STRENGTH VERSUS TEMPERATURE FOR DIFFERENT MUDS (FROM SRINI-VASAN 1957)



Annis (1976) was capable of investigating the gel strength up to temperatures of 350°F. Srini-Vasan observed that the gel strengths leveled off after 160°F but Annis noted that at higher temperatures a rapid increase in the gel strength was noted. Figure 17 reflects this observation. Thus increased temperature, like increased bentonite concentration promotes flocculation. The temperature at which a rapid increase in gel strength occurs, represents the onset of flocculation. Therefore it is possible to expect the gel strength to increase significantly at some elevated temperature.

Annis studied the gel strength properties of about 40 water base field muds at temperatures ranging to 300°F. The muds covered a wide range of densities and mud types, although the majority were lignosulfonate muds. To draw conclusions on the effects of high temperature on gel strength, the gel strength properties were averaged and are presented in Figure 18.

Hiller (1963) noted that some clay suspensions display a decrease in gel strength with increased pressure, especially at high temperatures. It was noted that the gel strength was reduced to 1/4 of its original value for a pressure increase from 300 to 8000 psi at a temperature of 302°F. This reduction in the gel strength resulting from increased pressure is presented in Table 6.

Although no direct means exists to determine the ultimate gel strength of a drilling mud at borehole conditions, it is possible to safely say that the gel strength developed in the borehole is considerably greater than that indicated by the initial and 10 minute gel strength recorded for a given mud. The effects of time, temperature and pressure on the gel strength of the static mud column have been discussed above. In the range of pressures and temperatures normally encountered in disposal formations, pressure should exert a negligible effect on the gel strength. Flocculation at high temperature should not occur except in the deepest of disposal formations. Certain muds do not display a temperature dependence, but the effect of time is ever present.

The research discussed above investigated muds with 0 initial gel strength to ultimate gel strengths of 100's lbs/100SF. In an attempt to select a minimum ultimate gel strength that could be expected for the worst of mud and borehole conditions, a value of 20 lbs/100 ft^2 should be utilized for the ultimate gel strength in all gel strength pressure calculations where actual numbers are not available. This value will provide a considerable safety factor in most cases.

The 20 lb/100 ft^2 ultimate gel strength was arbitrarily selected to insure that a sufficient safety factor is built into the proposed procedure. The selection is the result of individual judgment prejudiced by the above discussion."

FIGURE 17

EFFECTS OF TEMPERATURE AND BENTONITE CONCENTRATION ON 30 MINUTE GEL STRENGTH (FROM ANNIS 1976)

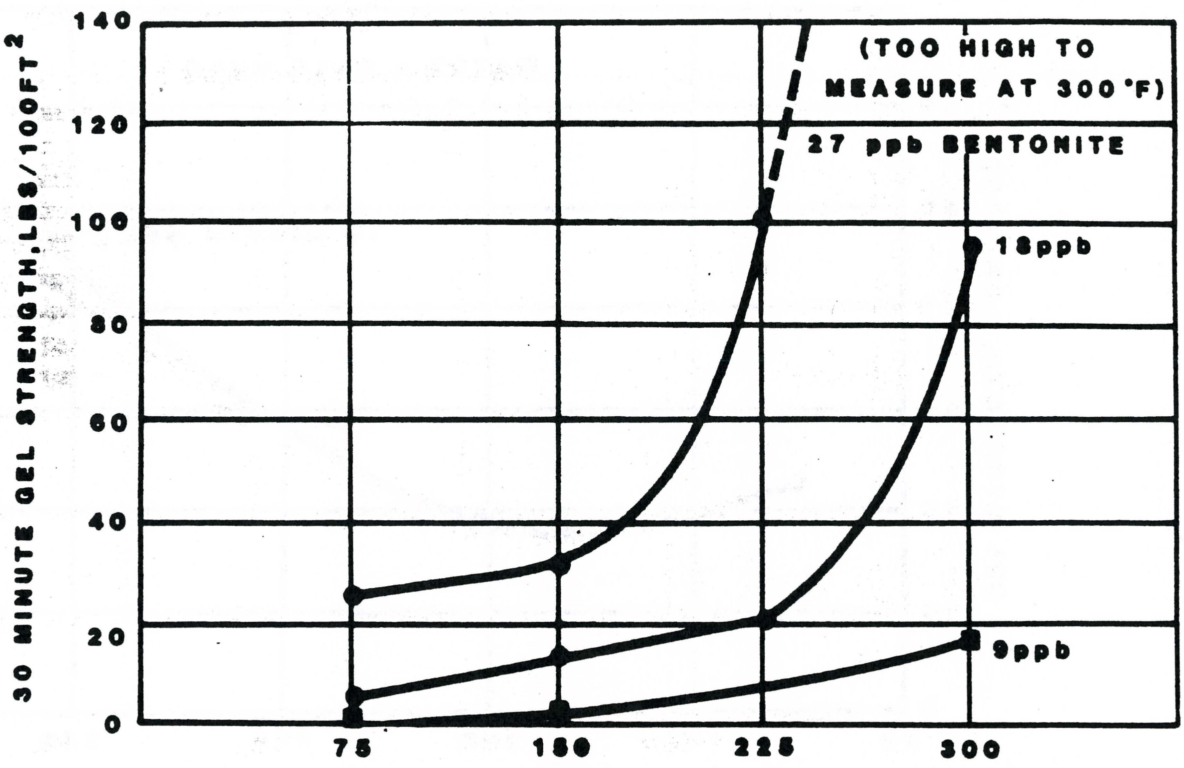
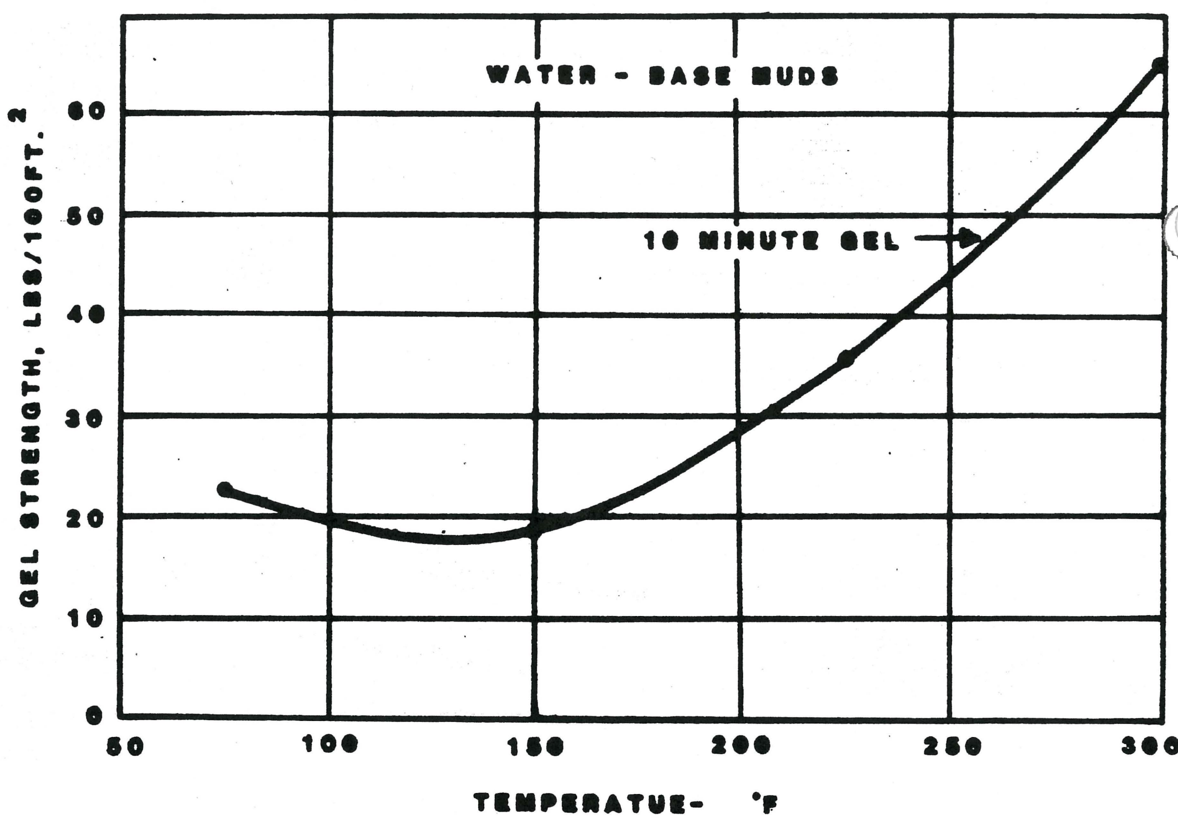


FIGURE 16

EFFECT OF TEMPERATURE ON 10 -MINUTE GEL STRENGTH (FROM ANNIS 1976)



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About the Author

Ken E. Davis, President of Ken E. Davis Associates, 3121 San Jacinto, Suite 102, Houston, Texas 77004, has extensive experience in the field of injection well systems used for secondary recovery disposal and storage. He has either personally installed or been responsible for the installation of over fifty (50) Industrial Disposal Wells and over one hundred (100) Salt Water Disposal Wells in the continental United States, Europe and Mexico. He has also worked as technical advisor to the Environmental Protection Agency on their Underground Injection Control Program authorized by the Safe Drinking Water Act, The Department of Energy on their various Underground Storage Programs and The Bureau of Reclamation on their various salinity control projects.

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APPENDIX 4-11

Appendix 4-11

Technical Basis for Area of Review (Collins, 1986)

CMA

CHEMICAL MANUFACTURERS ASSOCIATION

RECEIVED

JAN 14 1987

TO: UIC Management Group
UIC Reg Neg Team

FROM: Emily Currie EMC/

DATE: January 8, 1987

SUBJECT: Area of Review Final Report

Enclosed for your information is the final report on "Technical Basis for Area of Review" by Research & Engineering Consultants Inc. This report has been approved by the UIC Modeling Work Group. Should you have any questions, please call me at 202/887-1103.

TECHNICAL BASIS FOR AREA OF REVIEW

An Engineering Study

Prepared for

Chemical Manufacturers Association
Washington, D.C.

by

REC

RESEARCH & ENGINEERING CONSULTANTS INC.

TECHNICAL BASIS FOR AREA OF REVIEW

An Engineering Study

Prepared for

Chemical Manufacturers Association
Washington, D.C.

by

R. Eugene Collins, Ph.D. P.E.
Research & Engineering Consultants Inc.
Butte, Montana

November 7, 1986

CMA Reference Number: 80-160-000-4

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APPENDICES

EXECUTIVE SUMMARY

This study of "area of review" procedures designed to protect underground sources of drinking water (USDW) in underground injection operations for waste disposal using deep wells, has examined two major areas:

(1) Potential pathways for contamination of USDW by underground wastes

(2) Factors affecting areal distribution of pressure increase in a brine aquifer used for underground injection of liquid wastes

Results of the study indicate that the <u>most significant pathway</u> for contamination of USDW is through abandoned, unplugged wellbores. However, the study has also shown that a major factor limiting entry of brine, or injected wastes into abandoned wells is the gel characteristics of mud in these wells. This study indicates that in most cases the contribution of the gel property to the critical pressure increase required for fluid entry into the wall may be more significant than previously thought.

The problem then in assigning an area of review for a deep well injection system is two-fold; first, one must determine locations of abandoned wells and assign <u>realistic</u> values for mud and hole properties which determine the critical pressure in the injection zone, P_{crit}, at each well, which determines on-set of leaking, and second, one must make realistic forecasts of pressure history in the injection zone at the location of each abandoned well. This forecast of pressure history should reflect effects of known near boundaries in the injection zone, sealing faults or non-sealing faults, leaky shale aquicludes and anisotropic permeabilities.

This study demonstrates that these geological features of the injection zone can sometimes result in pressure build-up significantly above that forecast by the simple "Theis" equation commonly used by most government regulatory bodies to estimate the "radius of endangered influence" of an injection well. We also show in this study that since shales have a small, but non-zero, permeability there can occur a pressure build-up less than this Theis equation forecast, but this is not generally very significant.

The existence, or non-existence of these geological features can usually be confirmed through detailed analysis of the transient pressure response of the injection well to a given injection rate history, and its interaction with neighboring wells communicating with the same injection zone (if such exist) after the well is put into operation for an extended period of time. However, prior to installation of the well the existence of such geological features cannot be ascertained with any confidence unless detailed pressure response data, in addition to well logs and similar data, are available on several near-by wells operating in the same zone.

Therefore we recommend an area of review process which exploits all available data as effectively as possible. Thus if there are not any nearby wells in the same injection zone then assignment of an area of review would be based upon the Theis equation using a dimensionless type curve, as set forth in this report, using best available estimates of pertinent injection zone parameters. However, if adjacent wells do exist, and injection rate and pressure histories on these wells can be obtained, then we recommend analysis of these pressure transient data to detect geological non-uniformities of the proposed injection zone. Then a computer program, similar to that used in this study, could be used to compute a more realistic "zone of endangered influence" due to the proposed well which incorporates these geological features.

After the proposed well is installed, and operated for an extended period of time, the actual injection rate - pressure history of the well could be used in a similar computer program to substantiate the existence of these geological features. This would be a history matching process achieved through adjustment of parameters in the computer program representing geological features in a simulation of well performance.

INTRODUCTION

I. Defining Area of Review

In compliance with the Safe Drinking Water Act of 1974, and subsequent amendments, the Environmental Protection Agency (EPA) has developed minimum requirements for state operated programs regulating subsurface disposal of industrial liquid wastes by injection through wells. Such underground injection control (UIC) regulation has the objective of protecting underground sources of drinking water from contamination by brine or injected wastes. These regulations define an "Area of Review" which is based upon the premise that within this area, centered on the injection well, pressures within the injection zone may cause migration of the injected fluid and/or formation brine into an underground source of drinking water (USDW) through some pathway breaching the sealing layer of the injection zone.

This area of review has been defined by regulatory agencies in terms of a radius of review assigning then a circular area centered at the injection well. This radius of review is defined by calculating a "zone of endangering influence" of the injection well or, as a fixed radius from the injection well, whichever is the larger. This fixed radius varies from state-to-state; in states where EPA has primacy, the fixed radius is 1/4 mile, while in states having primacy, the fixed radius varies from 1/4 mile to 2 1/2 miles. These various approaches to area of review specification are reviewed in a guidance document prepared by Engineering Enterprises (1985).

Calculations reported in the literature for estimating the "zone of endangering influence" have been based primarily on a single well of constant rate in an infinite aquifer using the "Theis Equation" (1935) but it is generally recognized that superposition of such solutions can be employed to treat multiple wells and wells with variable rate. (Collins, 1961).

Barker (1981) presented a systematic procedure for defining the area of review but his treatment was limited to a single, constant rate well and totally ignored effects of reservoir heterogeneities and boundaries. However, his treatment was the first to consider the contribution of mud gel strength as a sealing mechanism in abandoned boreholes.

Davis and Sengelmann (1986) presented a general overview of the area of review problem and expanded on the contribution of mud gel as a sealing mechanism. Their review discussed procedures for including multiple injection wells and variable injection rates in the analysis but again reservoir heterogeneities and boundaries were ignored.

With this background, the study described in this report was undertaken with the objective of providing a sound technical basis for definition of an area of review. Factors investigated were:

* Potential breaches of the sealing layer (potential pathways for contamination of USDW by fluids from the injection zone)

* Factors determining the temporal evolution and spatial distribution of pressure increase in the injection zone

II. Potential Pathways for Contamination of USDW From Deep Well Injection Operations

Pathways by which injected fluid, or brine from an injection zone, might migrate up to a fresh water zone are:

(1) A channel in the injection well grout (primary cement behind injection well casing)

(2) A hydraulically induced fracture at the injection well

(3) A natural fracture

(4) A fault

(5) A permeable sealing layer, or aquiclude, over the injection zone (a "leaky aquifer")

(6) An abandoned well bore

The first of these is readily ruled out if modern well completion practices are followed. The petroleum industry has been evolving cementing procedures for more than sixty years and a well-defined process exists to assure a cement sealed annulus between well casing and bore-hole. State and Federal regulations require that the well be cased and cemented to surface. Of course, old injection wells, installed prior to the introduction of these regulations, might not be constructed to these high standards and a pathway, or "channel" for vertical communication behind casing could exist. However, methods do exist to test such wells for the existence of vertical flow channels behind the casing; noise logs, temperature logs and radio-active tracer surveys are used for this purpose. (Schlumberger, 1973; McKinley, 1982) There is also a new type of logging tool, the oxygen activation radioactivity log (Arnold and Paap, 1979) which is extremely accurate and sensitive for detection of water flow channels but it has not been made commercially available. Some states do require periodic radio-active tracer tests of all Class I injection wells to confirm the absence of vertical communication of flow channels behind casing.

The second potential pathway, a hydraulically induced fracture, will not occur if a well is operated according to regulations because these require that injection pressure gradient never exceed the critical fracture gradient for breakdown of the formation. Furthermore, even if a hydraulic fracture did occur, field experience in the oil industry has demonstrated that vertical fracture growth is terminated in thick shale layers. (Williams et al, 1979)

Therefore if the aquiclude immediately above the injection zone is a thick shale, no pathway to USDW could occur by this process.

The third pathway, a natural fracture, could be a potential pathway to USDW only in an improperly selected site for an injection well. Generally, natural fractures do not extend great distances vertically except in areas that have been very active tectonically, e.g. in the vicinity of salt domes. Deep sedimentary basins in tectonically stable regions will be free of this threat to USDW. Major factors also contributing to this security are creep under overburden load and secondary mineralization which tend to eliminate fractures as fluid pathways.

For example, on the Texas Gulf Coast, faulting and associated fracturing, have been described by Edwards (1982), Han (1981), Bebout et al (1982), Bruce (1973), Ewing (1983) and many others as arising as growth faults. Such faults occur due to gravitational slumping of accumulating sediments along the continental shelf. Thus such faults and fractures evolve in young sediments. Subsequent compaction by accumulating overburden induces closure by creep and secondary mineralization as brines in deeper sediments are expelled upward along such fractures. Typical of clastic formations exhibiting such old fractures in this region is the Miocene age Oakville Sandstone. Evidence for ancient ground water movements through fractures in this formation, resulting in secondary calcite cementation filling the fractures is described by Galloway (1982). Thus, in most cases these fractures are no longer vertical fluid pathways. Furthermore, since these growth faults, and associated fractures develop in young sediments, they typically do not extend upward through subsequent deposits.

Faulting associated with salt domes may be very extensive and complex. There is perhaps less assurance of no vertical pathways for fluid movement in deposits overlying, or flanking a salt dome, than in basin deposits not disturbed by such intrusions. (Braunstein et al, 1968)

Faults may act as totally sealing lateral boundaries for an aquifer if shale is displaced to totally occlude the permeable aquifer, or as a partially sealing boundary if only a portion of the aquifer section is occluded by shale. For extreme cases, different sands can be juxtaposed.

In the petroleum industry, shales have generally been viewed as impermeable because oil and gas are found held in "traps" by shale layers, as for example in an anticlinal structure of a sandstone overlain by a shale layer. Clearly the upward migration of hydrocarbons is stopped by shales. However, this means only that the water saturated shales are more impermeable to oil and gas than to water.

In the case of oil and gas displacing water from a shale, there is an interface phenomenon which comes into play to inhibit upward permeation. This phenomena is not present for miscible displacement by water, and results from surface tension effects which produce a "capillary threshold entrance pressure" opposing oil or gas entry into the shale.

The existence of a uniform gradient of hydrostatic pressure down through sedimentary layers of sandstones and carbonates, alternating with shales, clearly demonstrates a non-zero permeability for water in shales. Also, a phenomenon termed "compaction drive" is used in the petroleum industry to describe expulsion of water from shales into an adjacent permeable sandstone oil reservoir as the reservoir is depressurized by oil production. A similar phenomenon is associated with subsidence due to water withdrawal from shallow aquifers as in the Houston, Texas ship channel area. There large volumes of water have been withdrawn from shallow sand aquifers for chemical plant use in the area. As these sands are depressured the overlying and underlying shale layers expel water into the sand by darcy flow with associated volume reduction in the shale - hence, subsidence of the surface occurs.

The phenomena just described, which indicate non-zero permebility to water in shales, do not require a large permeability in order to occur. Over geologic time, an almost infinitesimal shale permeability would permit establishment of a uniform hydrostatic gradient in pore-filling water (brine). Furthermore, calculations of the volumetric contribution of compaction drive in oil production indicate that shales need have permeabilities only as small as 10^{-6} md in order to account for a significant compaction drive contribution to oil recovery because of the very large sand-shale area involved.

A considerable body of literature has accumulated which treats problems of "leaky aquifers", meaning permeable shale aquicludes (see bibliography) but there does not seem to exist any public domain literature on actual measurements of shale permeabilities.

A personal communication from Dr. Paul Witherspoon, Director of the Earth Sciences Laboratory at Lawrence Berkeley Laboratory informed us that Prof. Neville Cook of that facility has just embarked upon a project to measure shale permeabilities using a transient flow technique. This is very similar to measurements carried out by Brace et al (1968) on permeabilities of granite and other "impermeable" rocks. Dr. Cook pointed out that most theoretical calculations of permeabilities of shales are on the order of 10^{-3} to 10^{-6} md. One method of making such calculations, uses the Kozeny equation (Kozeny, 1927), (Brooks and Purcell, 1952), (Collins, 1961) which relates permeability to specific pore surface area, and porosity with surface area in turn related to grain size and packing.

It is important to note that both permeability and thickness of a shale layer are significant in determining the effectiveness of the layer as a sealing aquiclude. This is expressed in the quotient of vertical shale permeability and thickness, K_{zs}/h_s. A very thick shale of moderate permeability overlying an aquifer could then augment the storage capacity of the aquifer through "leak-off" of brine into the shale yet still limit upward migration to USDW and serve as an aquiclude.

In our studies of "leaky" shales, we have therefore modeled this contribution to slowing an aquifer pressure build-up by specifying the quotient value, K_{zs}/h_s for such shales. Later we will see computer output using this in which h_s is stated to be one foot but this is not to be taken literally; this simply means that the variability in the quotient K_{zs}/h_s for various runs was introduced as a change in K_{zs} only.

Without question, item (6) of our list of potential pathways for USDW contamination has been given central consideration by all government agencies having responsibility for UIC programs. Indeed, an abandoned and unplugged, uncased wellbore does seem, at first sight, to be an "open conduit" for flow from an injection zone up to USDW. However, this is really <u>not</u> the case but the main focus of our study has been on abandoned wells. Having essentially ruled out the first five potential pathways for contamination of USDW as <u>very</u> unlikely in a properly sited,constructed and operated injection well, it is indeed abandoned wells which should be addressed by further study.

<u>III. The Abandoned Well Mud Seal</u>

In most areas of the United States that are geologically suitable for deep well injection operations for industrial liquid waste disposal rotary drilling with drilling mud, as opposed to air rotary drilling or cable tool drilling, has been the method of choice since the early part of this century. Sedimentary basins which have extensive deposits of clastic layers separated by laterally continuous shale layers offer the most suitable sites for injection operations.

Shale formations, especially the geologically younger formations of the U.S. Gulf Coast, are very difficult to drill using cable tools. These have been termed "gumbo" shales, or sloughing, shales. Caving and sloughing of such shales causes great difficulty in cable tool drilling; as a consequence essentially every well drilled on the Gulf Coast since about 1920 has been rotary drilled (Suman, 1921). Furthermore, only a few wells were drilled to depths greater than 3500 feet prior to about 1920 and therefore essentially <u>all</u> abandoned dry holes on the Gulf Coast contain drilling mud.

Producing oil or gas wells which were subsequently abandoned would typically have at least one complete string of casing bottom-hole to surface and more modern wells would also have a shallow protection casing fully cemented from about 1500 feet to surface. The primary production casing would be cemented from bottom-hole to some point subsurface above the producing zone, with the remaining part of the annulus filled with drilling mud. Unfortunately old cementing techniques were not very satisfactory, so much of the annular seal would of necessity be contributed by mud in the annulus.

At abandonment, a well would typically be "killed" with mud and, in "modern" times, since about 1935 (Texas) cement plugs have been required by state regulations <u>within</u> the casing to "seal" hydrocarbon producing zones but cement plugs to protect fresh water have been required only since 1957 (Texas). This 1957 regulation stipulated that the short string (surface protection string) be cemented in its entirety and the deepest "useable" water be protected by a cement plug from 50 feet below to 50 feet above the zone (Steed, 1984).

Drilling mud is a suspension of finely divided bentonite (primarily montmorillonite type) clay in water (or brine) with weighing agents (principally barite) and additives to control rheology, density and filtration characteristics. Oil base muds have also been used with the objective of providing greater stability of shales against sloughing. Shales penetrated by the well can experience significant water exchange with the drilling fluid due, essentially, to an osmotic process dependent upon ionic activity of the mud and the brine in the shale. This water exchange (see Gray & Darley, 1981) can lead to expansion of the shale and sloughing off into the hole.

Because of the colloidal characteristics of these drilling muds, they exhibit the thixotropic property of a <u>gel strength</u> upon remaining in a quiescent, unsheared state for a period of time. This gel strength is defined as the maximum static shear stress sustained by the gelled mud without "breaking the gel". Gel strength is usually measured with a concentric cylindrical cup viscometer. With mud allowed to stand in the cup for a period of time, a measured torque is applied to the moveable cup while the concentric cylindrical boundary remains fixed. This torque is slowly increased until rotation occurs and this maximum torque then is used to compute gel strength from the geometry of the system. This instrument is usually referred to as a Fann Viscometer.

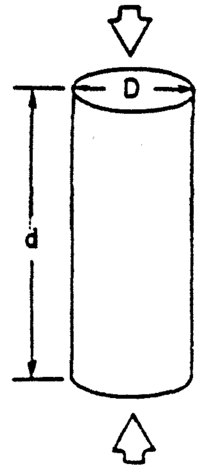
The significance of gel strength, G , in contributing to the mud seal of an abandoned well is seen by the following considerations. Assuming a bore hole of diameter D filled with mud of uniform weight density ρ_m we can write the force balance defining equilibrium, or no motion of the column, as indicated indicated in Figure 1 as follows:

$$\text{Pressure force, up} = \frac{\pi D^2}{4} P$$

$$\text{Weight force, down} = \frac{\pi D^2}{4} \rho_m d$$

$$\text{Shear force at wall, down} = \pi D G d$$

P = 0.0 (Gauge)



P (Gauge)

FIGURE 1

Thus equating upward forces to downward forces yields:

(1) $$\frac{\pi D^2}{4} P = \frac{\pi D^2}{4} \rho_m d + \pi DGd$$

where d is the total height of the mud column. (Typically from the injection zone to surface.) If this is expressed in conventional oil field units, we obtain for P in psi,

(2) $$P = 0.52 \rho_m d + 3.33 \times 10^{-3} \frac{Gd}{D}$$

where d is in feet, D is in inches, ρ_m is in lb/gal and G is in lb/(100ft^2). If we then subtract, from P, the normal original pressure in the injection zone, P_o = .052 where ρ_B is the density of slightly saline water, 8.4 lb/gal., we have the excess pressure contributed by the mud column

(3) $$P - P_o = .052 (\rho_m - \rho_B) d + 3.33 \times 10^{-3} \frac{Gd}{D}$$

Now a minimum mud weight for bentonite mud is about 8.6 lb/gal. (Gray & Darley, 1981) and for fresh water mud G will be about 50 lb/100 sq.ft. For a 5000 ft. of 9 5/8" diameter hole this yields

(4) $$P - P_o = 52 + 86.5$$

Thus gel strength contributes 86.5 psi as sealing pressure while mud weight contributes 52.0 psi. Even the lowest possible gel strength that could occur, about 20 $lb/(100ft^2)$, (Gray & Darley, 1981) would still yield 34.6 psi contributed by gel strength. Thus, gel strength provides a <u>significant portion</u> of the pressure differential $P - P_o$.

Now in the original state, prior to injecting into the disposal zone, reservoir pressure, in a normally pressured stratum in <u>any</u> sedimentary basin, will be that corresponding to hydrostatic equilibrium at the depth of the zone, i.e. P_o. Then we see $P - P_o$ as the <u>pressure increase</u> at the abandoned well that would be required to <u>initiate</u> brine leakage from the zone into the well. Therefore, the general criterion for leakage through the abandoned well is

$$(5) \qquad \Delta P \geq 0.052\ (\rho_m - \rho_B)\ d + 3.33 \times 10^{-3}\ \frac{Gd}{D}$$

where ΔP is the increase in pressure in the injection zone, caused by fluid injection in the zone, above original reservoir pressure at the location of the abandoned well. On the right, d is the subsurface depth, in feet, to the injection zone, at the abandoned well, ρ_m and ρ_B are average mud density in the abandoned well and average brine density from surface to the injection zone, both in lb./gal., G is effective gel strength of the mud in the hole, in $lb./(100ft^2)$ and D is the average diameter of the abandoned hole in inches.

Now this is the same criterion used by Barker (1981) and subsequently elaborated to an annular configuration for pipe in the hole by Davis and Sengelmann (1986), and while physically plausible it had never been tested prior to this study.

This "leak criterion" is based on the hypothesis that fluid entry cannot occur until pressure over the base of the mud column is sufficient to lift the entire column but this may not be totally realistic. Thus some simple laboratory experiments were designed to test this criterion. An apparatus was first constructed as shown in Figure 2. This pipe was filled with a bentonite mud with some brine put into the viewing tube on top of the core after the Berea sandstone core plug in the bottom had been saturated with brine through a filling tube from below. This mud was allowed to gel for about 12 hours then brine pressure in the core was slowly increased until movement of the brine miniscus was detected in the transparent viewing tube on top of the column. The pressure increase at this point was compared to that predicted by Eq.(5). What was found was a bit surprising at first; it was found that if the gel strength, G, as measured on a sample gelled for 12 hours in a Fann instrument, was used in this equation, a value of ΔP much <u>less</u> than the observed value was calculated. A partial explanation for this was found in the effect of the irregularities in diameter of the pipe in the fittings shown above.

In fact, it was found in experiments with several variations of this apparatus, using larger diameter pipe, multiple diameter irregularities, etc., that the <u>effective</u> gel strength, G', that must be inserted into Eq.(5) to correctly predict the critical pressure increase for brine entry into the mud-

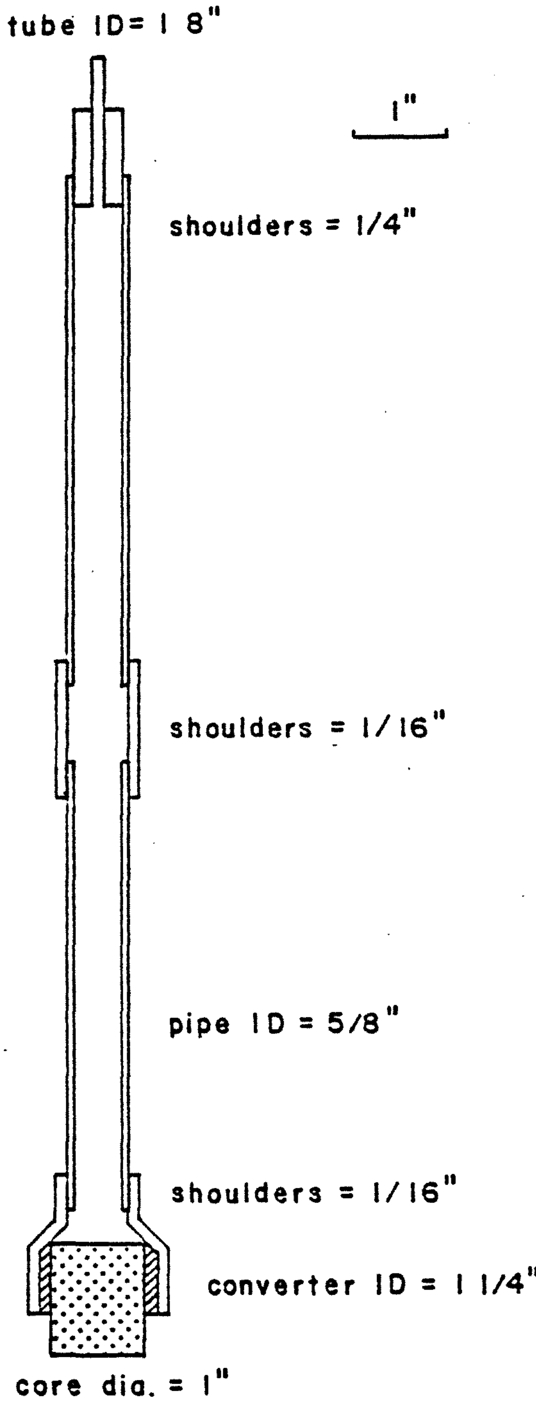


FIGURE 2

filled column was many fold larger than the actual gel strength. These experiments are described in detail in Appendix B.

These experiments suggest that there is an apparent increase in critical entry pressure contributed by hole irregularities roughly given by

(6) $\Delta P_G = n\, \Delta P_{Gel}\, \varepsilon$

Here ΔP_{Gel} is the calculated value for gel contribution for a straight cylindrical hole, as in Eq.(5), n is the number of hole-diameter irregularities and ε is a dimensionless parameter characteristic of the geometry of these irregularities, all assumed to be identical. With this, we would alter Eq.(5) to read

(7) $\Delta P \geq 0.052\,(\rho_m - \rho_B)\, d + 3.33 \times 10^{-3}\, \frac{G'd}{D}$

where G' defined by

(8) $G' = (1+n\varepsilon)G$

is the apparent gel strength for the mud in the irregular hole. In fact, this is the basis used to compare and evaluate various simulated hole geometries in Appendix B. There the ratio G'/G=R was found to fall in the range of 1.68 to 5.76.

Unfortunately, the data from these experiments was not free of ambiguities; for example, one experiment with a smooth pipe free of irregularities in diameter yielded a G'/G of 1.99 instead of unity as expected. Thus, additional study of factors contributing to the sealing pressure by mud in an abandoned hole is called for, but these data suggest that mud gel and hole irregularities interact to yield a large contribution to sealing pressure.

For example, in Eq.(4), the minimum mud weight contribution to sealing pressure in the 5000 foot hole was computed as 52 psi above ambient original pressure, and for a minimum mud gel of 20 $lb/(100ft^2)$, a contribution of 34.6 psi was computed. In view of the experiments described here, we speculate that in a real wellbore with typical shale "washouts" and other irregularities, this number might be increased by as much as ten fold. Then mud gel would contribute 346 psi as compared to 52 psi by mud weight. However, much additional research is required before these results can be used quantitatively with confidence.

There are other questions to be answered with respect to the sealing role of mud in abandoned boreholes. First of all is the question of mud density. Muds used in rotary drilling are always selected to "over-balance" fluid pressures in penetrated formations thus

(9) $\rho_m - \rho_B > 0$

and a difference of 0.2 lb/gal is very conservative. However, mud left standing in an abandoned hole does undergo density changes due to gravitational settling of heavier particles as will be described shortly.

Gel characteristics of mud determined in the laboratory show a limiting gel strength achieved in a relatively short time, as seen in Figure 3. These data, obtained by Garrison (1939), are typical and the curves are well approximated by

$$(10) \qquad G = G_\infty \frac{at}{1 + at}$$

where G_∞ is the <u>ultimate</u> gel strength and "a" is a rate constant. Values of "a" and G are determined by replotting the data of one of these curves as t/G versus t.

$$(11) \qquad \frac{t}{G} = \frac{1}{G_\infty} t + \frac{1}{aG_\infty}$$

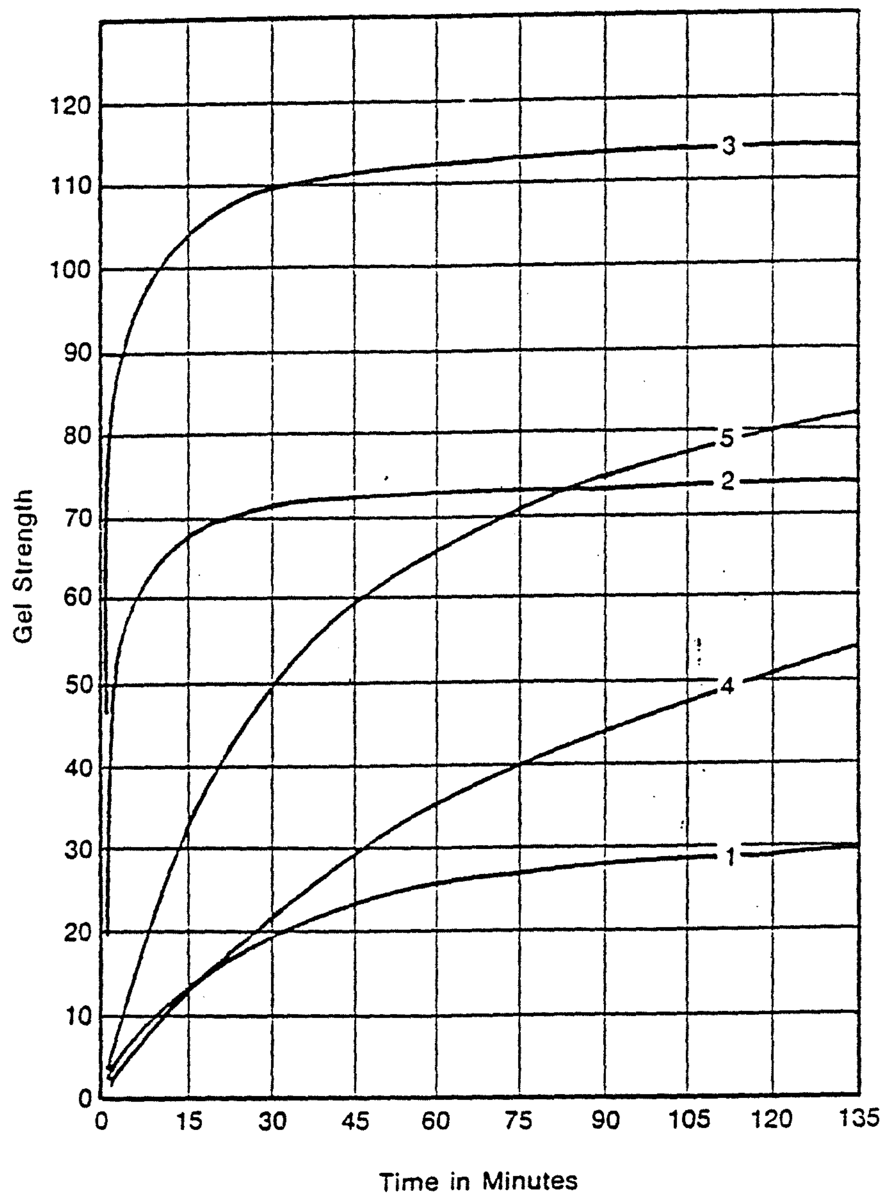
Thus slope, $1/G_\infty$, and intercept, $1/aG_\infty$ are determined. Table I shows some typical values for the parameters G_∞ and a as determined in this manner for bentonite suspensions. These data demonstrate distinct effects of bentonite concentration and pH of the mud.

Gel strength normally reported in drilling records is the <u>10-minute gel strength</u>. The data of Figure 3 clearly show that this value may be many-fold smaller than the ultimate gel strength, G_∞. Furthermore, this "ultimate gel strength" is yet smaller than the gel strength actually developed by mud in an abandoned hole, because Eq. (11) is only an approximation to the true gel strength buildup, and does not accurately describe the experimently observed behavior at long times (beyond a few hours).

TABLE I
(From Garrison, 1939)

<u>CONSTANTS IN GELLING EQUATIONS OF BENTONITE SUSPENSIONS</u>

Bentonite Per Cent	Gel Strength and Rate	pH+ 9.2	pH+ 9.3-9.5	pH+ 9.9-10	pH+ 10.8-11
4.5	G_∞	34.4	40.1	48.5	69.6
4.5	a	0.047	0.071	0.076	0.063
5.5	G_∞	74.4	82.2	129.9	152.7
5.5	a	0.75	0.22	0.13	0.18
6.5	G_∞	114.0	141.0	250.0	268.0
6.5	a	0.79	0.30	0.10	0.25



120
110
100
90
80
70
60
50
40
30
20
10
0
Gel Strength
0
15
30
45
60
75
90
105
120
135
Time in Minutes
3
5
2
4
1

FIGURE 3

The range of compositions that might be encountered in old muds is too great to try to categorize for this study but we can try to set some lower bounds expected for mud weight and gel strength.

There is some information available indicating the effect of "aging" on mud gel strength and this is critical in our assessment of the actual gel strength for old muds. Certainly the "ultimate" gel strength G_∞ defined above is not the value we expect in an abandoned well. Table II, from the work of Weintritt and Hughes (1965), illustrates to some degree the effect of aging on muds of different composition (see lower part of Table II) even though these progressive gel measurements were carried only to 16 hours.

Two sets of this data are plotted in Figure 4. It is very clear that gel strength continues to increase long after the "ultimate strength" plateau of Garrison's formula is apparently reached. Thus extrapolation of short-term gel measurements based upon the Garrison formula can be totally misleading. Gel strengths of truly old muds may be orders of magnitude greater than the "ultimate gel strength" indicated by the Garrison extrapolation, but more research is needed on this question.

Another aspect of aging of mud is settling of suspended solids and heavier particulates. Cooke, (1983) (1984), in the course of field experiments designed to evaluate processes occurring in primary cementing operations, made direct determinations of change in the weight density of mud left standing in a drill hole over the course of eleven months. Surface-recording pressure transducers were mounted at various points on casing prior to running and cementing in the hole in seven different wells. Since cement was not run to surface in the annulus, those sensors in this mud-filled portion of the annulus gave information on changing density of mud with time. This was a water-base, bentonite mud weighted with barite to 11.0 lb/gal. It was found that sedimentation reduced this to 9.1 lb/gal in eleven months.

The gel characteristics of old mud in abandoned wells have not been investigated quantitatively, but qualitative field observations of mud recovered from re-entered holes (Chenevert, 1986) indicate extremely high gel strength. Such old muds will be predominantly made up of finer particulates of bentonite (montmorillonite, illites and kaolinites) from the original prepared mud and shales penetrated by the hole. Heavier particulates and cuttings will have settled to the bottom of the hole.

Now in spite of the great variability in mud properties that might be found in abandoned wells, it is possible to assign lower bounds for mud weight and effective gel strength for purposes of looking at worst case scenarios. Thus we should expect that if a hole had been drilled with cable tools, it would contain only natural brine that seeped into the hole plus some solids that sloughed from the walls due to exposure to this water. Finer particles of montmorillonite would have remained in suspension to create some gel strength but heavier solids would have settled to the bottom of the hole. Such holes can be treated as "mud" filled holes with a ρ_m of about 8.5 lb/gal and a gel strength of roughly 15 to 20 lb(100 ft^2) which are typical for dilute bentonite muds (Gray and Darley, 1980). Note however, in computing the

TABLE II
Comparison of Mud Properties with Progressive Gel-Strength Tests
Gyp-Ferrochrome Lignosulfonate Emulsion Muds

	SAMPLE			
	Mud E	Mud F	Mud G	
			No Treatment	3 lb/bbl PCL
Weight, unstirred, lb/gal	11.0	10.7	10.6	
Weight, stirred, lb/gal	11.0	10.3	10.7	
Plastic Viscosity, cp	14	23	16	15
Yield Point, lb/100 sq ft	3	6	2	1
10-sec gel, lb/100 sq ft	1	2	1	0
10-min gel, lb/100 sq ft	8	8	7	3
API filtrate, ml	6.2	3.3	5.2	2.9
ph	10.9	10.6	10.5	10.4
Composition: Water % by vol	76	63	75	
Oil % by vol	5	11	9	
Solids % by vol	19	16	16	
Solids % by wt	39	36	37	
Solids, Sp.Gr.	2.7	2.9	3.0	
Filtrate Ion Analysis:				
Chlorides ppm	3500	400	3000	
Sulfate, epm	250	300	130	
Carbonate, epm	24	28	12	
Bicarbonate, epm	12	160	12	
Calcium, epm	44	52	44	

Progressive Gel Strengths (lb/100 sq ft)	Temperature (°F)							
Time	75°	180°	75°	180°	75°	180°	75°	180°
0 minutes	1	1	2	2	1	1	0	0
3 minutes	2	3	2	5	3	8	1	1
10 minutes	8	18	8	12	7	26	3	3
30 minutes	15	40	11	18	17	58	5	5
60 minutes	27	90	18	16	29	91	6	6
2 hours	31	145	22	22	29	104	7	7
4 hours	37	190	29	42	46	172	10	10
8 hours	46	190	33	42				
16 hours	880	320	40	57	95	320	25	25

critical pressure increase to initiate fluid entry, an effective gel strength due to hole irregularities of greater magnitude is suggested by the experiments described earlier.

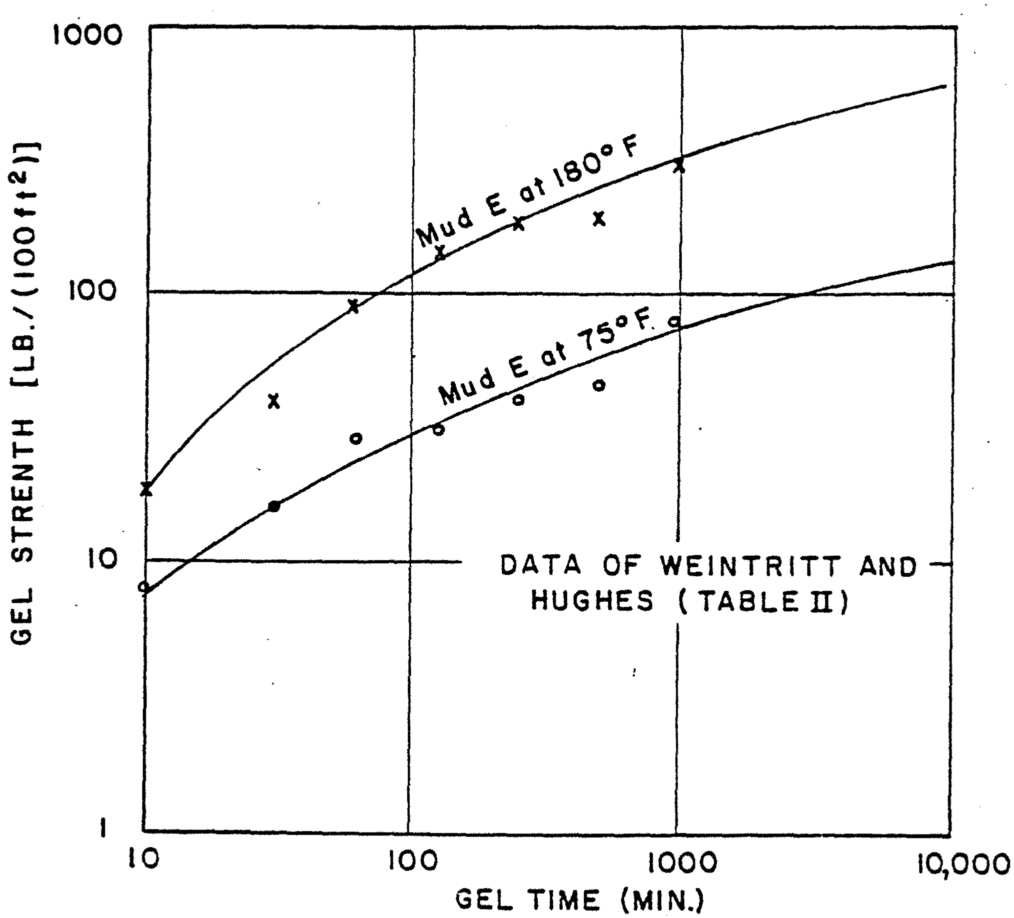


FIGURE 4

For rotary drilled holes, a minimum mud density of 8.6 lb/gal must exist but a probable mud density of 9 lb/gal is likely.

Actual gel strengths of 80 to 300 lb/(100 ft^2) are indicated from the previous discussion but a much larger effective gel strength is again suggested by our experiments.

IV. The Simulation Model: Mathematical Background

We have identified abandoned wells as the overriding potential pathway for contamination of USDW from deep well injection in a properly sited, properly constructed and properly operated injection well system. We have also established a criterion for on-set of leakage of brine, or injected fluid, in an abandoned well in terms of a critical pressure rise at the abandoned well site in the injection zone. Thus, we now come to the central consideration of this study, that is the forecasting of the distribution of pressure increase in the injection zone for the design lifetime of the well, and, for that matter, all future time. The forecast of pressure increase is designed to exhibit effects of sealed reservoir boundaries, anisotropic permeabilities, leaky shale aquicludes and partially sealing faults which permit flow transverse to but not tangent to the fault plane.

The method selected for these forecasts of pressure, or flow potential, distribution histories is a mathematical simulation based upon analytical solutions to the basic partial differential equation describing two-dimensional plane flow in the injection zone. It is assumed that the fluid is slightly compressible, of uniform density, and uniform viscosity within a permeable stratum of rock. This stratum may be anisotropic in the plane of the stratum, but is uniform in all other pertinent properties, except at transecting plane discontinuities. Thus the injection stratum may consist of one, two or several large "blocks", each with uniform porosity, ϕ_o, permeabilities K_x and K_y, thickness h, etc. joined at plane interfaces.

The reader should be aware that the approximation of a layered stratum of rock as a uniform stratum provides very accurate estimates of pressure or flow potential distributions; it is only required that the thickness-weighted average of the permeabilities of the layers be assigned as the permeability for the homogeneous stratum in any one direction. It is also necessary in the case of anisotropic permeability that the principal axes of permeability (direction of maximum and minimum permeability) be the same for all layers. Similar assignment of thickness-weighted average porosity is required.

The basic partial differential equation has the form

$$(12) \qquad \frac{K_x}{K}\frac{\partial^2 \bar{\psi}}{\partial x^2} + \frac{K_y}{K}\frac{\partial^2 \bar{\psi}}{\partial y^2} - \alpha\,(\bar{\psi}-\bar{\psi}_o) = \frac{\phi_o \mu c}{K}\frac{\partial \bar{\psi}}{\partial t}$$

where the coordinate axes, x, y are on a horizontal datum plane and oriented parallel to the principal axes of permeability in the formation. The derivation of this equation is given in Appendix A. The function ψ is the flow potential defined by

$$(13) \qquad \bar{\psi} = \bar{P} + \rho_o g H(x,y)$$

with $H(x,y)$ the height of the midpoint of the rock stratum above a datum plane, at location x,y. Here ρ_o is the fluid density at original average reservoir pressure and $\overline{P}$ the pressure at this location in the stratum at time time t. The bar over ψ indicates that this is the value of ψ averaged over the thickness h of the stratum. The other quantities appearing here are:

μ = fluid viscosity

$K = \sqrt{K_x K_y}$

ϕ_o = reservoir porosity at original pressure conditions

$c = c_\phi + c_f$ where

c_ϕ = pore compressibility of rock

c_f = fluid compressiblity

$\alpha = K_{zs}/Khh_s$

$\overline{\psi}_o$ = initial uniform potential

and

K_{zs} = permeability of shale sealing layer

h = thickness of injection zone

h_s = thickness of shale sealing layer

We should note here that the leaky shale coefficient, α , is just the reciprocal of the characteristic length, B , introduced by Hantush and Jacob (1955).

It is assumed that initially, prior to start of injection, hydrostatic equilibrium exists throughout the injection zone, the shale sealing layer and an overlying brine aquifer immediately on top of the shale sealing layer. Thus $\overline{\psi}_o$ is the uniform value throughout these bodies intially and it is assumed that even though flow through the "leaky shale" occurs at a rate

$$\text{(14)} \qquad \begin{array}{l}\text{leak rate per}\\ \text{area of shale}\\ \text{overlayment}\end{array} = \frac{K_{zs}}{\mu} \quad \frac{\overline{\psi} - \overline{\psi}_o}{h_s}$$

the overlying aquifer is so thick and permeable that the potential in that aquifer remains at potential $\overline{\psi}_o$ everywhere for all time. Certainly this is an approximation, just as the "instantaneous steady-state" leak rate per unit area, given in Eq.(14), is an approximation, but these approximations allow estimation of effects due to "leaky shales". Neglecting the buildup of back pressure in the overlying aquifer tends to underestimate the pressure increase in the injection zone at long times, while neglecting the compressional storage capacity of the confining shale layer tends to overestimate the pressure increase in the injection zone; thus the above approximation is conservative.

Other investigators used these same approximations, Hantush and Jacob (1955), Hantush (1960), Miller et al (1986), while there have been some more "sophisticated" approximations employed by others in the treatment of multiple leaky aquifers, Chen and Herrera (1982), Herrera (1970), and others. (See Bibliography) The advantage of this approximate description for the "leaky shale" problem is that we have been able to show that, by using the analytical solution for a single well of constant rate, we can use the superposition principle, and method of images, to write solutions for reservoirs having various boundaries and variable injection rates just as for the non-leaky shale case. The latter is well described in the text by Collins (1961).

At the other extreme of "leaky" shale approximations is that of an effectively <u>infinitely thick shale</u> in which we assume vertical but not lateral flow. In this case, we show in Appendix A that the leak rate of Eq.(14) is replaced by

(15) leak rate per area of shale overlayment $$= \frac{K_{zs}\phi_s c}{\pi\mu}\int_0^t \frac{\bar{\psi}(x,y,\tau) - \bar{\psi}_o}{\sqrt{(t-\tau)^3}}\, d\tau$$

and it is clear here that the main contribution to the integral is in a <u>small</u> neighborhood $\Delta\tau$ of $\tau = t$. Thus this can be <u>approximated</u> as

(16) leak rate $$\approx \frac{K_{zs}}{\mu}\sqrt{\frac{\phi_s \mu c}{\pi K_{zs}\Delta\tau}}\,(\bar{\psi}(x,y,t)-\bar{\psi}_o)$$

which has the <u>form</u> of Eq.(14) with an h_s given as the reciprocal of the radical appearing here. Thus the leaky shale model we are employing is capable of simulating the storage effect due to leak off of brine into a <u>thick</u>, slightly permeable aquiclude, at least to an approximate degree.

We should note of course that a shale aquiclude <u>acts</u> as an infinitely thick layer so long as no pressure increase has occurred in the overlying aquifer. From the analytical solution for a step increase in injection zone pressure (see Carslaw & Jaeger,(1973) p.101) this will be valid for an injection time t such that $K_{zs}t/\phi_s\mu c h_s^2$ is less than 0.05.

The analytical solution to Eq.(12), for the non-leaky case, $\alpha = 0$, corresponding to a single well of constant rate q starting at time $t = 0$ and located at position x_w, y_w is: (Collins, 1961, p. 115)

$$(17)^* \qquad \bar{\psi} - \bar{\psi}_o = \frac{q\mu}{4\pi Kh}\{-Ei(-\frac{\phi_o \mu c}{4Kt}[(x-x_w)^2 \frac{K}{K_x} + (y-y_w)^2 \frac{K}{K_y}])\}$$

Then the coordinate substitutions

$$(18) \qquad x' = x\sqrt{\frac{K}{K_x}}, \quad y' = y\sqrt{\frac{K}{K_y}}$$

reduce this to the form

$$(19) \qquad \bar{\psi} - \bar{\psi}_o = \frac{q\mu}{4\pi Kh}\{-Ei(-\frac{\phi_o \mu c}{4Kt}[(x'-x'_w)^2 + (y'-y'_w)^2])\}$$

which has been called the "Theis equation" in hydrology literature after the publication by Theis (1935), but actually this should be called the "Kelvin equation", if it is to have an individual's name, because it was Lord Kelvin, the famed English physicist, who first published this equation in his transient heat conduction studies.

What is shown by this coordinate substitution is that the anisotropic solution, Eq.(17), looks exactly like the isotropic solution, $K_x = K_y = K$, in the transformed coordinates. Thus while the contours of equal potential are circles about the injection well in the isotropic case,

$$(20) \qquad (x-x_w)^2 + (y-y_w)^2 = r^2 = \text{constant}$$

these becomes ellipses

$$(21) \qquad \frac{(x-x_w)^2}{(K_x/K)} + \frac{(y-y_w)^2}{(K_y/K)} = \text{constant} = r^2$$

in the anisotropic case. Thus if for example $K_y > K_x$, then the ratio of maximum distance from the well, $(y - y_w)$, to minimum distance, $(x - x_w)$, at

* Here the Ei-function is defined by $-Ei(-z) = \int_z^\infty \frac{e^{-\lambda}}{\lambda} d\lambda$

which a given pressure increase will occur is

$$(22) \qquad \frac{(y - y_w)_{max}}{(x - x_w)_{min}} = \sqrt{\frac{K_y}{K_x}}$$

Thus in anisotropic reservoirs, which are appropriately described by equations of this type, pressure build-up from fluid injection will be greatest, and occur earlier in the direction of maximum permeability.

Ample field evidence of such anisotropy has been accumulated from studies of some oil reservoirs such as the Spraberry Field in northwest Texas. (McCarthy and Barfield, 1958; Elkins and Skov, 1960)

In Appendix A, we show how to add solutions of the type in Eq.(17) to simulate variable rate wells in domains bounded by linear lateral fault planes. This includes, for example, wells within a rectangular domain or in a semi-infinite reservoir bounded by fault planes making an angle θ_T with each other.

These same techniques are shown to apply to an injection well in a stratum bounded above, and/or below, by a "leaky shale" layer. This is based on the solution of Eq.(12) for a single well of constant rate q_a, starting at time zero, located at x_w, y_w in an infinite stratum. This solution, obtained by Collins (1986), has the form

(23)

$$\bar{\psi} - \bar{\psi}_o = \frac{q_a \mu}{4\pi K h} \left[e^{-\frac{\alpha}{\beta} t} \{-Ei(-\frac{\beta r^2}{4t})\} + \int_o^t e^{-\frac{\alpha}{\beta}\lambda} \{-Ei(-\frac{\beta r^2}{4\lambda})\} \frac{\alpha}{\beta}\, d\lambda \right]$$

where α is the leaky shale parameter defined for Eq.(12) above and β is $\phi_o \mu c/K$, the reciprocal of hydraulic diffusivity. The derivation of this solution is given in Appendix A. The pseudo steady-state form of this solution is also given there and it is shown that in the steady-state limit, $t \to \infty$, this reduces to the form published by Hantush and Jacob (1955).

$$(24) \qquad \psi - \psi_o = \frac{q_a \mu}{2\pi K h} K_o(\alpha r)$$

Another particular solution for Eq.(12) that has been adapted in the simulator is one obtained by Yaxley (1985) to describe a well near a <u>partially sealing</u>

fault. His description is for a single well at distance B from the fault in an <u>isotropic</u> reservoir with a <u>sealed</u> <u>aquiclude</u> but by coordinate substitutions, as described above in Eq.(18), and elaborated in Appendix A, his solution can be adapted to anisotropic cases.

The partially sealing fault is contrasted to a totally sealing fault in the following diagram.

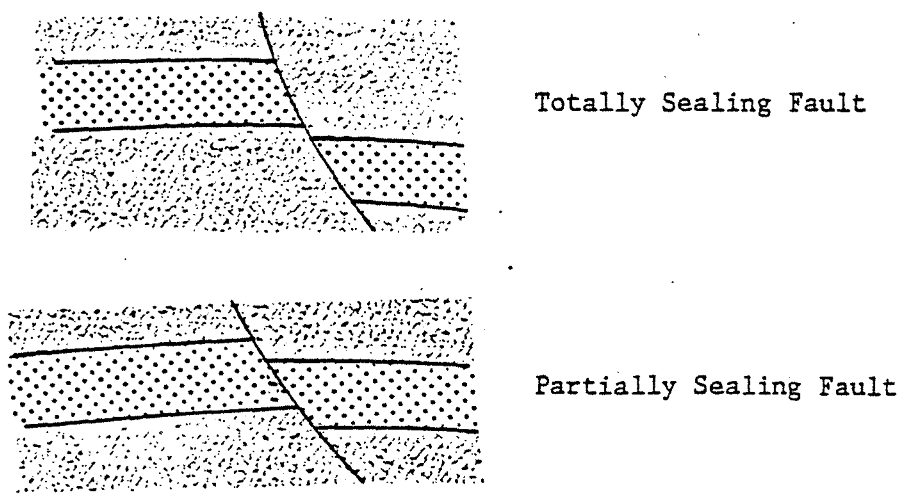


FIGURE 5

Yaxley describes the solution of this problem in terms of the geometry of Figure (6).

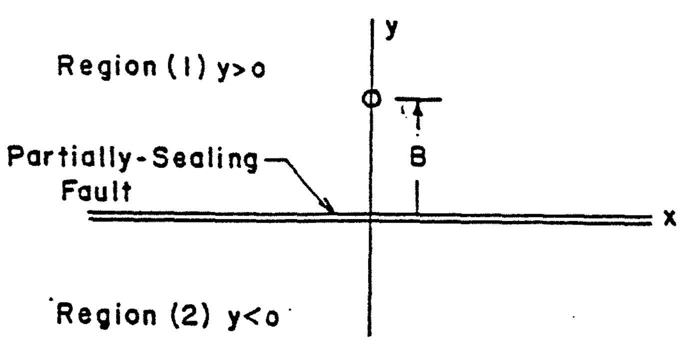


FIGURE 6

The presence of the fault introduces a discontinuity in flow potential, across the fault, proportional to the fluid flow rate normal to the fault at a given point. Thus with $\overline{\psi}_1$ (w,y,t) the solution in the domain y > 0 and $\overline{\psi}_2$ (x,y,t) that in the domain y > 0 the boundary condition along the fault, y = 0, is

$$(25) \qquad \frac{K_f}{\mu \ell_f} [\overline{\psi}_1(x,\ell_f,t) - \overline{\psi}_2(x,o,t)] = \frac{K}{\mu} \frac{\partial \overline{\psi}_1}{\partial y}(x,\ell_f,t)$$

where the fault is visualized as a strip of width ℓ_f having permeability $K_f<K$. This is employed in the limit $\ell_f \rightarrow 0$ with the dimensionless coefficient defined by

$$(26) \qquad \alpha_f = \frac{K_f}{\ell_f} \frac{B}{K}$$

i.e., Eq.(25) is as $\ell_f \rightarrow 0$ and $K_f \rightarrow 0$ with K_f/ℓ_f finite and non-zero,

$$(27) \qquad \frac{\alpha_f}{B} [\overline{\psi}_1 (x,o,t) - \overline{\psi}_2 (x,o,t)] = \frac{\partial \overline{\psi}_1}{\partial y} (x,o,t)$$

The forms for these solutions for $\overline{\psi}_1$ and $\overline{\psi}_2$ are given in Appendix A in a dimensionless format. These involve a rather complex integral involving a complimentary error function which must be evaluated numerically for each computation of $\overline{\psi}_1$ or $\overline{\psi}_2$. This has been implemented in our simulator.

Effects of spatially variable permeability are not incorporated in this simulator but in Appendix A, a mathematical model is described which permits assessment of effects of non-homogeneous permeabilities.

V. The Simulation Model; Practical Description

Input Data:

(1) Injection Reservoir Properties

- K = permeability, md
- h = thickness, ft
- ϕ_o = porosity, fraction
- μ = fluid viscosity, cp
- c = effective compressibility, psi^{-1}

(2) Sealing Layer Properties

K_{zs} = shale vertical permeability, md

h_s = shale thickness, ft

(Note: these enter calculations only as K_{zs}/Khh_s

(3) Reservoir Geometry (Sealed Boundaries)

Box geometry, length L (ft), width W (ft)
or
Semi-infinite geometry bounded by two faults intersecting in vertex angle, θ_T , degrees
or
Infinite reservoir, no faults
or
Infinite reservoir transected by one partially sealing fault

(4) Injection Well Data

Injection well coordinates
Injection well rates and starting times
(A variable rate option is available)

(5) Abandoned Well Data

Abandoned well coordinates
Depth, subsurface, to injection zone
Mud weight density and effective gel strength
Borehole diameter

(6) Partially Sealing Fault

k_f = fault "permeability", md

ℓ_f = fault "width", ft

(Note: these enter calculations only as K_f/ℓ_f

(7) Total Run Time

This is the design lifetime of the injection wells under study.

(8) Time-Step

This is the time interval between evaluations of pressure build-up at all abandoned wells. When the critical pressure to leak is exceeded at a well on any time step interpolation using three steps is used to fix the time of onset of leaking.

Output Data

(1) Time (in years) for an abandoned well to begin leaking

VI. Case Studies

The problem in assigning an area of review for a deep well injection system is two-fold; first, one must determine locations of abandoned wells and assign realistic values for mud and hole properties which determine the critical pressures in the injection zone, P_{crit}, at each well, which determines on-set of leaking, and second, one must make realistic forecasts of pressure history in the injection zone at the location of each abandoned well. This forecast of pressure history must reflect effects of near boundaries in the injection zone, sealing faults or non-sealing faults, leaky shale aquicludes and anisotropic permeabilities.

The collection of case studies given in Appendix C is intended to provide clear examples illustrating the effect of various system parameters on the leak time, or time of on-set of leaking, in abandoned wells. Following is a list of studies.

Case Studies List

I. Effects of sealing fault boundaries and well locations

II. Effects of abandoned well parameters

III. Effects of partially sealing faults

IV. Effects of "leaky shale" aquicludes

V. Effects of anisotropic permeabilities

VI. Effects of finite reservoir volume

Format: Case Study Examples

In each case study, well and reservoir data are given as above, then a map is given indicating locations of wells and boundaries. On this map, an open circle is an abandoned well that did not leak during the lifetime indicated on the map while a solid circle indicates an abandoned well that did leak. The notation by a well such as t_L = 1.6 yr, indicates the time in years after initiation of injection when leaking began at that well. The injection well is marked by a circle with an arrow through it.

We have elected to use one set of abandoned well locations and a single injection well so that comparisons between various runs on the simulator are facilitated. However, in some instances, deviations from this pattern have been made.

Discussion of Case Studies

Case I - Effects of Sealing Faults

The examples given here clearly demonstrate that for any specified critical pressure for leaking of an abandoned well, the presence of no-flow boundaries near the injection well accelerates leaking by virtue of more rapid pressure increase in the reservoir. This phenomenon is sensitive to location of the injection well relative to these "fault" boundaries. One example of detailed pressure histories at wells is also shown.

Case II - Effects of Abandoned Well Parameters

The examples in this case study clearly demonstrate that the assumed values for effective mud properties in abandoned holes greatly affects the time for onset of leaking. Even in the worst case of two nearby fault boundaries (45^{o} angle between faults) an increased value of P_{crit} significantly delays onset of leaking.

Case III. Effects of Partially-Sealing Faults

Here, comparisons are made between the effect of a single, partially-sealing fault and a totally sealing fault traversing the reservoir near an injection well. Clearly, the totally sealing fault has greater effect in inducing earlier leaking of wells on the injection well side of the fault. However, even a partially-sealing fault is effective in preventing leakage of wells on the other side of the fault. The presented examples show a clear trend for the effect of the fault "conductivity factor", $\alpha_f = K_f B/K\ell_f$, on the time of onset of leaking of abandoned wells.

Case IV. Effects of Leaky Shales

The examples presented here show the potential for "leaky shales" to prevent leaking of abandoned wells. The first set of runs exhibits a worst case comparison for two faults at 45^{o}. With all other parameters equal, the times for onset of well leaking in the leaky shale case are two to six times longer than in the non-leaky shale case. It can be shown from the steady-state solution that leaky shales display a pressure build-up to a finite pressure at long times so an abandoned well may never leak in some cases.

Case V. Effects of Anisotropic Permeabilities

Only a limited demonstration of effects of anisotropic permeability is given here. The case of $K_x/K_y = 4$ has been illustrated in one well pattern. The higher permeability in the x-direction, and lower in the y-direction, with the same $\sqrt{K_x K_y} = K$ as in the isotropic runs, is equivalent to moving wells further apart in the y-direction and closer together in the x-direction. The resulting times for on-set of leaking reflect this very clearly.

In field operations, the only methods available for detecting effective anisotropy, or measuring it, are based upon well interference effects, or tracer techniques. Thus multiple wells must be available for such tests.

Case VI. Effects of Finite Reservoir Volume

Of all factors considered here, finite reservoir volume can be by far the most detrimental to injection well operations. The examples given demonstrate very clearly that pressure build-up is excessively rapid and leaking of abandoned wells occurs very early in reservoirs of small pore volume. Increasing reservoir area, thickness and porosity reduces the onset of leaking of abandoned wells. Fortunately such reservoirs essentially do not exist in large sedimentary basins. Moreover, their presence can be detected during the recommended initial post-construction test phase of the well operation.

VII. The Type Curve Concept

In view of the many factors affecting the onset of leaking in abandoned wells, we have considered the possibility of employing type curves for evaluating "area of endangerment" from injection operations. These would be families of curves generated as graphs of the dimensionless quantity

$$\Delta P_D = \frac{4\pi Kh}{q\mu} (\bar{\psi} - \bar{\psi}_o) \tag{28}$$

plotted versus a dimensionless distance, r_D, from the injection well in a specified direction. (Angle θ above a selected axis) These could be shown for various dimensionless times, leak parameters and reservoir geometries. Clearly this would require an enormous catalogue of curves in order to cover all possible cases.

Furthermore, in order to use such curves, one would need to know the subsurface geometry of faults and a very large list of parameters of the reservoir, leaky shales and partially-sealing faults. These data are never available at the design or construction stage of an injection well. Therefore, we propose only one type curve and this is described in the following section.

VIII. Recommended Area of Review Process

Our simulation studies have clearly demonstrated that the temporal evolution of the pressure distribution in an injection zone is greatly altered by a variety of geological features. We have exhibited effects of sealing and partially-sealing faults, leaky shales, anisotropic permeabilities and differences in porosity, permeability and thickness of the disposal zone as well as effects of well locations in the zone.

Since all of these factors do have an effect on the pressure distribution in the injection zone, and its evolution in time, we should determine their configuration, or values, prior to constructing the injection well but in most cases this is impossible and we must employ an area of review process that does not require such prior knowledge.

Certainly we should use all of the best geological evidence available from all sources; logs from neighboring wells, seismic traces, and definitely pressure transient behavior of any neighboring wells operating in the planned injection zone, if such wells exist. Ideally, if enough appropriate data are available then simulation studies could be carried out, using a simulator similar to that developed for this study, to evaluate the pressure influence of the proposed well in the injection zone. Then a very accurate assessment of long-term pressure build-up at every abandoned well near the proposed well could be made.

The method of exploiting such a simulator would be to first establish a "pressure-history match" to well pressures of all existing neighboring injection wells, for their given rate histories, by adjustment of geological parameters of the injection zone in the simulator. Then injection rate histories for the proposed well, and all neighboring wells operating in the same injection zone, would be specified for the future and pressure history forecasts could be made. Thus the future pressure history at every abandoned well would be computed. With these data we would then apply the on-set of leaking criterion, described below, for each abandoned well.

Generally, sufficient pressure-rate data on neighboring wells will not exist for such a history matching process so we propose a two-stage area of review process; a pre-construction area of review study and a post-construction area of review process. These are described as follows.

Pre-Construction Area of Review

Best available estimates of the proposed injection zone porosity, ϕ_o, permeability, K, thickness, h, and effective fluid-rock compressiblity, c, must be made using information from other wells drilled and cored, or tested, in the same zone.

The design rate and lifetime of operation for the proposed well must be assigned. Then a minimum mud weight of 8.6 lb/gal and a minimum effective gel strength of 10 $lb/100ft^2$ is assigned.

These data are then to be used with the "Theis" equation

$$\bar{\psi}-\bar{\psi}_o = \frac{q\mu}{4\pi Kh}\{-Ei(-\frac{\phi_o \mu c r^2}{4Kt})\} \tag{29}$$

to assign an initial area of review estimate, i.e. a well leaks at distance r from the injector during the lifetime, t, of the injector for rate q if